Attachment 8.2

Opex Business Cases

January 2025

PUBLIC

Dampier Bunbury Pipeline

CONTENTS

1 Opex DBP05: Turbine overhauls

1.1 Project approvals

Table 1.1: DBP05 Turbine overhauls – Project approvals

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1.2 Project overview

Table 1.2: DBP05 Turbine overhauls – Project overview

Description of problem /opportunity	Gas turbines provide an important role in operating the pipeline. They enable pressure to be maintained appropriately given operational requirements. This business case outlines the ongoing preventative maintenance required for identified gas turbines to ensure continued efficient performance. When these assets become deficient in performance, individual assets are selected for overhaul based on criteria identified in the relevant Asset Management Plan, supported by the manufacturer (such as in the original equipment manufacturer (OEM)) specification). The key criterion for identifying performance issues that may drive the need for a unit to be overhauled is the number of hours individual assets have been in operation. This business case identifies which gas turbines need to be overhauled to maintain performance and includes: • drivers for the need for overhaul; • method of forecasting hours; • assessment of untreated risk; and • potential impact of failing to undertake overhauls as guided by the AMP and OEM. This business case also outlines the cost and how the identified assets are prioritized based on expectation of failure and changes in operational hours.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Move to a replacement on failure policy (no upfront costs) • **Option 2** – Proactive overhaul based on expected runtimes and two premature failures ($29.3 million) (this is the recommended option) • **Option 3** – Proactive overhaul based on expected runtimes and three premature failures ($32.5 million)
Proposed solution	Over the AA6 period, five turbines will reach their maximum running hours of 30,000 hours before they need to be overhauled. We expect one turbine to be exchanged each year, with a higher cost in 2029 as it is [redacted]. We have also assumed two premature failures on the basis that we have experienced three premature failures over the last two access arrangement periods.

We will also continue our varnish removal program assuming two per year to complete the program for all units installed in stage 3 and 4 expansions.

Estimated cost

The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $29.3 million ($Dec2024).

Turbine exchange and overhaul	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Premature failure	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Varnish removal unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**4,156**	**7,406**	**4,156**	**6,160**	**8,106**	**29,284**

Basis of costs

All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.

Treated risk

As per risk matrix = **Intermediate**

Variation from AA5

The forecast expenditure for AA6 is consistent with the expected expenditure in AA5 of $29.4 million.

Alignment to our vision

Our proposed turbine overhaul program delivers against all relevant vision objectives of delivering for customers, being a good employer and being sustainably cost efficient. It maintains our assets in line with manufacturer's guidelines and in a planned and controlled manner, adjusting priority assets as appropriate based on actual run hours. It also leads to a safer environment for employees and contractors, allowing them to operate in an environment where risk is proactively managed.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 91 – Proactive overhaul of gas turbines maintains the safety, integrity and reliable delivery of gas along the DBNGP by ensuring gas turbine units are available as required to meet customer demand. Proactively overhauling, in line with manufacturer recommendations and over 35 years of operational experience, ensures these assets continue to perform efficiently and represents a more cost-effective solution over the life of the asset than full replacement. It also helps to avoid catastrophic failure of an engine, which can lead to costly replacement with extended outage on the pipeline. Therefore, it is consistent with the expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

NGR 74(2) – Our forecasts for when overhauls will fall due are based on the latest information on run hours, utilisation and expected throughput. The forecast cost per overhaul is based on a three-year average historical cost and current prevailing foreign exchange rates. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circvumstances.

Stakeholder engagement

Our Shippers require current levels of reliability to be maintained and expect effective emergency management. Our gas turbine overhaul program comprises ongoing and periodic activities to ensure the integrity, reliability and effective capability to respond to emergencies.

Other relevant documents	This Business Case should be read in conjunction with: • Asset Management Plan (TEB-001-0024-07) • AMP TEB-001-0024-03 (Rotating Equipment) • Risk Management Policy and Operational Risk Model (together our Risk Management Framework)

1.3 Background

All physical DBNGP assets are managed in accordance with the policies and principles set out in the Asset Management Plan (AMP) which is part of our Asset Management System Framework.

A key principle of the Asset Management System Framework is effective management of asset risks which includes identification of risks and evaluation of the adequacy of controls in terms of physical safeguards and asset maintenance requirements. These controls are often supported by the relevant manufacturer's warranty and/or maintenance guidelines.

As part of the asset management risk assessments, risk levels are determined for different asset classes and criticality of controls analysed based on the significance of risk reduction provided by the risk controls.

Gas turbines are critical assets within the DBNGP, and proactive (preventative) maintenance of them is equally critical to ensure the safe and reliable supply of gas to customers and to prevent the associated financial impact which could be experienced in the event of a catastrophic failure.

The purpose of a gas turbine driven compressor unit is to boost gas pressure in the pipeline. There are [redacted] primary gas turbine driven centrifugal gas compressor unit types installed at DBNGP compressor stations, supplied by different manufacturers. They are:

[redacted]

Maintenance of [redacted] is carried out in accordance with OEM recommendations, though modifications can be made to OEM intervals to better suit DBNGP's operational requirements. The AMP identifies 30,000 run hours as the trigger for a planned overhaul of the [redacted] and 35,000 hours for [redacted], which is in line with that recommended in the manufacturers' specifications.

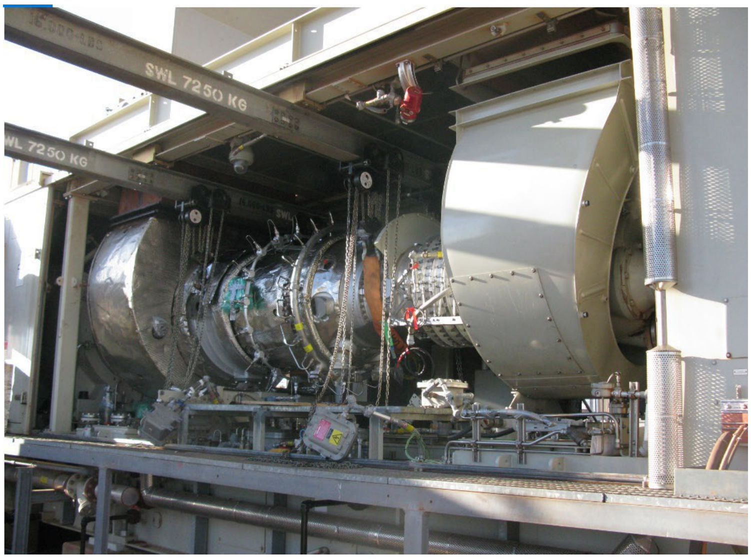
Gas turbines are considered high risk assets. A key control for managing this risk is preventative maintenance. The performance of these assets can be restored through replacement. Our approach to this is outlined in 'Asset Management Plan – Rotating Equipment (TEB–001–0024-03)', section 5.1.4.1.1 [redacted] and 5.1.4.2 [redacted].

Within the DBNGP, there are 20 (not including LM Units) gas turbines which need to be maintained in line with the AMP and manufacturers' specifications. Five of these are scheduled for overhaul in AA6. Overhaul of a gas turbine includes disassembly, inspection, repair and replacement of subcomponents, assembly and testing of the gas generator and/or power turbine component.

Figure 1.1 and Figure 1.2 below show the gas turbine being removed.

Figure 1.1: Gas turbine removal

Figure 1.2: Gas turbine overhaul



With scheduled (proactive) overhauls, the likelihood of failures in gas turbines is reduced, the cost associated with their maintenance is more easily forecast and logistical challenges associated with spare parts, which often have a long lead time, are optimally managed.

There are two gas turbines in each compressor station designed to operate in duty and standby mode with capability to operate in series for maximum capacity to deliver as demand calls for it. Critical units are identified based on their history of run hours. Each month, every unit is reviewed, and operational changes are made to optimise unit run hours and to ensure units reaching their overhaul targets are staggered and smoothed.

The monthly review allows for incorporation of externally driven changes to ensure run hours accumulated across the fleet are managed so that no more than two units can reach their overhaul target in any given year. Plant Operating Advice notifications are issued to the Control Room to identify units to be operated as 'duty' and those to be used as standby. Less hours are consumed on the standby units. This process is continually managed and monitored to ensure we meet our targets.

Failure to appropriately maintain gas turbines could result in significantly more expensive corrective maintenance when compared with a planned preventative overhaul, and could cause significant operational issues and cost, as catastrophic failure can result in a need for asset replacement and cause significant outages. Unplanned outages adversely impact on customers and result in a failure to deliver on contractual obligations. An unplanned outage resulting from a catastrophic failure which requires a new turbine to be installed could last up to three months and cost significantly more than a pre-emptive overhaul.

If there is an unplanned (preliminary) failure of a gas turbine within a warranty period and before the milestone for overhaul has been reached, we incur the field repair costs but are then compensated by the manufacturer when an overhaul on that turbine occurs. Over the last five years we have had three units prematurely fail.

The AA6 forecast can be seen relative to the AA5 and AA4 actuals and by individual asset in Table 1.3.

Table 1.3: Gas turbine overhaul program over time

Facility	Unit	AA3 delivered	AA4 delivered	AA5 planned	AA5 delivered	AA6 planned
CS1	1					✓
CS1	2			✓		✓
CS2	2	✓		✓	✓	
CS2	3		✓			✓
CS3	1		swapped	✓	✓	
CS3	3		✓			
CS4	2	✓				
CS4	3	✓	✓		✓	
CS5	1		✓		premature	
CS5	2		swapped			✓
CS6	2			✓		✓
CS6	3	✓		✓	✓	
CS7	1					
CS7	2		✓		premature	
CS7	3	✓				
CS8	1	✓	swapped	✓		
CS8	2	✓		✓*		
CS9	1	premature			premature	
CS9	2		✓		✓	
CS10	3					
CS10	4					
Premature				✓		✓ ✓
Total number		**8**	**6**	**7+1**	**5+3**	**5+2**

* Note CS8, unit 2 was planned for the last year of AA5 but forecast expenditure for this unit was not approved by the ERA. During AA5 we had to re-prioritise our expenditure plans to address prematurely failed units and have sought to manage this by changing our operations.

The AA6 forecast allows for five gas turbine overhauls, as shown in Table 1.3. This includes [redacted], which have different unit rates at [redacted] and [redacted] respectively. The schedule of overhauls is shown in Table 1.4.

Table 1.4: AA6 proactive gas turbine overhauls – units and cost

	2026	2027	2028	2029	2030	Total
Proactive overhauls ($'000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Number (units)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total cost ($'000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

We have also included an allowance for the replacement cost (opex) of two prematurely failed units. Although a reactive replacement is significantly higher in cost than a planned overhaul, it would be within the manufacturer's warranty period resulting in a lower unit rate than would otherwise be the case. This is consistent with previous periods where we have experienced at least one failure every two years - in AA5 we have had three so far. We have included an allowance of [redacted] in 2027 and 2030 to account for these expected costs.

Table 1.5 shows the gas turbines identified for overhaul and their current run hours as at October 2024 based on the operational strategy.

Table 1.5: Gas turbines for overhaul in AA6 - run hours

Facility	Unit	Type	Current hours	Proposed replacement
CS1	1	[redacted]	25,735	2026
CS2	3	[redacted]	24,766	2027
CS1	2	[redacted]	29,947	2028
CS6	2	[redacted]	28,151	2029
CS5	2	[redacted]	32,862	2030

1.3.1 Varnish removal

We also need to continue removing the varnish on the compressor turbine units installed as part of the Additional Compressor Stations (ACS) Stage 1 project, and Stage 2, 3 and 4 expansion projects.

Varnish is a sticky residue formed from the degradation of lubricating oil. Regular varnish removal can prevent costly repairs and downtime by keeping the system clean and functioning properly. We need to continue to remove this varnish to maintain optimal performance and reliability of our gas turbines.

Without regular removal varnish can:

- clog filters and restrict oil flow, leading to poor heat transfer and reduced efficiency;
- cause valve sticking and other mechanical issues, increasing wear and tear on components; and

- lead to fail-to-start conditions and unexpected unit trips, compromising the reliability of the turbine.

We expect to remove the varnish on [redacted] units per year over the AA6 period.

1.4 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, as shown below in Figure 1.3, with a commitment to balance outcomes sought with delivery considerations and cost assessment implications.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Figure 1.3: Risk management principles

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible.

The risk rating assesses the consequence and likelihood of the risk. The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS 2885 and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Modify the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

Six areas are considered for each type of risk:

1. People – injuries or illness to employees and contractors or members of the public
2. Environmental impact – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Supply – disruption in the provision of services/supply, impacting customers
4. Impact on AGIG/DBP – ability of AGIG (DBP) to operate the asset(s) without restrictions due to regulatory enforcement or legal actions
5. Reputation / outrage – impact on stakeholders' views of AGIG (DBP), including personnel, customers, investors, security holders, regulators and the community
6. Loss – financial impact on AGIG (DBP)

The primary risk event associated with turbines is that the failure of engines due to excessive run hour usage will lead to engine unavailability, engine damage as well as potential safety impacts where failure involves fragmentation of internal components. The overall risk rating of turbines is presented in Figure 1.4.

Figure 1.4: Untreated risk rating

	Trivial	**Minor**	**Severe**	**Major**	**Catastrophic**
Frequent					
Occasional		Environment	Reputation Supply	DBP Loss	
Unlikely					
Remote					People
Hypothetical					

Negligible	**Low**	**Intermediate**	**High**	**Extreme**

The drivers of the risk rating for each area are discussed below.

- **DBP** – the reliable operation of our gas turbines is critical to public safety and customer service/delivery. An integrity breach potentially costs millions of dollars in penalties and foregone revenue for both DBP and customers. The consequence of a gas turbine integrity issue is ranked major as it can threaten the effective operation of the DBNGP for a substantial period.

- **Loss** – without the planned investment in overhauling gas turbines, there is a high risk the asset will be damaged. Reactive costs to repair damage will likely escalate compared to the planned works program to maintain the design intent of the assets. Failure of a gas turbine could result in asset damage of between $10 million and $25 million where failure requires replacement of other components of the turbine package, or even full replacement of a compressor unit.
- **People** – gas turbines are located at compressor stations, which are used as a base for our field staff to operate. Given the potential consequences of serious injury if employees are working at these locations at the time of an integrity breach, it is imperative that the ongoing capex program maintains the risk of integrity issues as unlikely or remote. Maintaining high integrity at compressor stations, including through the ongoing maintenance of gas turbines promotes an acceptable level of safety workplace and shelter in emergencies for DBP employees. Allowing integrity levels to decline, and accepting a lower level of risk, would require personnel and sensitive equipment to be located away from compressor stations due to the failure consequences of high-pressure assets.

- **Reputation** – gas turbine overhauls are required to ensure equipment performs to acceptable standards. Inconsistent or unreliable performance due to underinvestment can lead to unplanned outages, which leads to irate customers. Underinvestment in integrity activities may lead to reputational damage and outrage internally as well as externally.
- **Supply** – gas turbines are integral to the effective operation of the DBNGP. Maintaining these assets is necessary to ensure DBP is able to safely and reliably deliver the forecast demand, as well as being ready to meet contractual obligations of shippers on any given day within the terms of shipper contracts.

1.5 Options considered

Different options have been considered to ensure our gas turbines continue to function safely, reliably and accurately. The options are:

- Option 1 – Move to a replacement on failure policy
- Option 2 – Proactive overhauls based on expected runtimes and two premature failures
- Option 3 – Proactive overhaul based on expected runtimes and three premature failures

The options are discussed in the following sections.

1.5.1 Option 1 – Move to a replacement on failure policy

Under this option, the volume of overhauls forecast in AA6 would reflect the number of breakages/outages experienced on these assets, with a reactive rather than proactive approach to the management of gas turbines.

1.5.1.1 Achievement of objectives

Table 1.6 outlines how this will support the achievement of our vision objectives in AA6.

Table 1.6: Achieving objectives – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

This option does not deliver for customers in terms of public safety or reliability, does not align with being a good employer in terms of health and safety of employees and contractors and is not sustainably cost efficient in terms of being environmentally and socially responsible.

This option would address only the assets which have failed, with a focus on returning them to being operational as quickly as possible, rather than proactively managing and planning for them. However, the failure of these assets is likely to result in significant disruption to services and higher cost due to the likely higher impact of the failure on the asset, including a higher likelihood of the need for replacement. A failure of these assets could also have significant impacts on the safety of workers in the vicinity of the failed asset.

As these units are limited to [redacted] hours run time, it is not safe to run these units over there maximum OEM defined lifespan as parts might become loose, causing damage to the asset and possible loss of life where it results in gas escape or explosion.

The unplanned impact to services could also lead to penalties of around $1 million/day due to breach of contractual arrangement with our major customers.

1.5.1.2 Cost assessment

The forecast cost of this option is unknown. However, given that the overhaul program is based on pre-emptive action, that is, preventative action is scheduled to occur before a failure is expected, a forecast of failures would reflect the forecast overhaul. However, the cost would be greater as the likely damage to assets may increase the cost of rectifying the issues for each unit. Therefore, this option is assumed to cost at least the same as the proactive replacement program. This option could cost significantly more to reflect the higher unit rate cost of rectification and penalty rates, potential damage to other assets, higher unit and freight costs to expedite delivery, and significant additional costs to customers of poor reliability and increased length of outages.

1.5.1.3 Risk assessment

Table 1.7 shows that Option 1 does not reduce the risk from the untreated risk and is not consistent with our Operational Risk Framework which requires us to 'moderate the threat, the frequency or the consequence to reduce the (overall) risk rank to intermediate or lower'.

Table 1.7: Risk rating impact - Option 1

Risk category	Untreated	Treated
People	Intermediate	Intermediate
Environmental	Low	Low
Supply	Intermediate	Intermediate
DBP	Intermediate	Intermediate
Reputation / outrage	Low	Low
Asset damage / Loss	Intermediate	Intermediate

1.5.2 Option 2 – Proactive overhaul based on runtimes and two premature failures

Under this option, the volume of overhauls undertaken in AA6 would be based on the criteria identified in the AMP, guided by the manufacturers' specifications for optimised maintenance of the asset and based on current forecasts for operational run hours.

An allowance would also be made to replace two units that fail prematurely. Should three be required as we have seen in AA5, we would need to reprioritise our overhaul schedule if possible, or, as has occurred in AA5, continue with the program, albeit on a slightly delayed schedule.

In AA6 we will also continue our varnish removal program to ensure all our units installed as part of the ACS Stage 1, and Stages 2, 3 and 4 expansion programs continue to operate in an efficient and reliable manner.

1.5.2.1 Achievement of objectives

Table 1.8 outlines how option 2 will support the achievement of our vision objectives in AA6.

Table 1.8: Achieving objectives – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	Y
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

This option delivers against all relevant vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it overhauls gas turbines in line with manufacturer's guidelines, in a planned and controlled manner, adjusting priority assets as appropriate based on actual run hours. It supports improved procurement outcomes, with proactive planning for freight and an opportunity to somewhat manage foreign exchange exposure. This option also leads to a safer environment for employees and contractors, allowing them to operate in an environment where risk is proactively managed.

1.5.2.2 Cost assessment

The cost of this option is $28.5 million in AA6. By adopting a proactive, planned approach to overhauls for our gas turbines, DBP can best manage the efficient delivery of the program, minimising the need for unplanned and disruptive repair work on the network, which might otherwise result in a failure on a gas turbine or a loss of supply.

The cost has been estimated by identifying the volume of overhauls required given the forecast operational hours and applying a unit rate relevant to the unit and assumption. Unit rates for planned gas turbines overhauls have been estimated as [redacted].

Within this option, there is an expectation that two gas turbines will prematurely fail, but will do so within the warranty period, resulting in a much lower cost for us than if it was outside the warranty period. All newly overhauled items are run at the highest possible activity rate to ensure any inherent weakness in the operations is identified within that warranty period, and that we are not disadvantaged financially from its failure when a unit is relatively new but outside the warranty period.

The overall cost of this option is shown in Table 1.9.

Table 1.9: Summary of AA6 forecast opex, real $,000 at December 2024

($'000)	2026	2027	2028	2029	2030	Total
Volume – Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Solar	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
Volume – Baker Hughes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Baker Hughes				[redacted]		[redacted]
Volume – Warranty	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Warranty		[redacted]	[redacted]		[redacted]	[redacted]
Varnish removal	[redacted]					
Total (volume)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total (cost)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Varnish removal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total opex	**4,156**	**7,406**	**4,156**	**6,160**	**7,406**	**29,284**

1.5.2.3 Risk assessment

Table 1.10 shows that this option does moderate the threat, the frequency and/or the consequence to reduce the overall risk rank to intermediate or lower consistent with our Operational Risk Framework.

Table 1.10: Risk rating impact - Option 2

Risk category	Untreated	Treated
People	Intermediate	Negligible
Environmental	Low	Negligible
Supply	Intermediate	Low
DBP	Intermediate	Low
Reputation	Low	Negligible
Loss	Intermediate	Low

This option appropriately addresses risks, reducing the inherent risk of these assets to as low and reasonably practicable (ALARP) with planned overhauls in line with manufacturers' guidelines to ensure gas turbines are available and can support our ability to deliver gas safely and reliably to meet the needs of our customers and gas producers.

However, we consider we can manage this risk for a short period of time by changing our operational strategy to run other turbines in preference to a failed unit, should three premature failures occur. This would increase the overhaul costs for AA7. However, we consider this is a more prudent option than budgeting for three premature failures as is included in Option 3.

1.5.3 Option 3 – Proactive overhaul based on runtimes and three premature failures

This option is the same as option 2 but allows for three premature failures of gas turbines as we have seen happen in AA5. Under this option we would need to change our operational strategy to accommodate the failed unit for a short period of time. This would increase the risk, and costs associated with turbine overhauls in AA7 should it occur.

1.5.3.1 Achievement of objectives

Table 1.11 outlines how option 3 will support the achievement of our vision objectives in AA6.

Table 1.11: Achieving objectives – Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

As with option 2, this option delivers against all relevant vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it overhauls gas turbines in line with manufacturers' guidelines, in a planned and controlled manner, adjusting priority assets as appropriate based on actual run hours. It supports improved procurement outcomes, with proactive planning for freight and an opportunity to somewhat manage foreign exchange exposure. This option also leads to a safer environment for employees and contractors, allowing them to operate in an environment where risk is proactively managed.

1.5.3.2 Cost assessment

The cost of this option is $28.6 million in AA6. By adopting a proactive, planned approach to overhauls for our gas turbines, DBP can best manage the efficient delivery of the program, minimising the need for unplanned and disruptive repair work on the network, which might otherwise result in a failure on a gas turbine or a loss of supply.

The cost has been estimated by identifying the volume of overhauls required given the forecast operational hours and applying a unit rate relevant to the unit and assumptions. Unit rates for planned gas turbines overhauls have been estimated as [redacted]. There is [redacted] scheduled for overhaul in AA6.

Within this option, there is an expectation that three gas turbines will prematurely fail but will do so within the warranty period. All newly overhauled items are run at the highest possible activity rate to ensure any inherent weakness in the operations is identified within that warranty period, and that we are not disadvantaged financially from its failure when relatively new but outside the warranty period.

Table 1.12: Summary of AA6 forecast opex, real $,000 at December 2024

($'000)	2026	2027	2028	2029	2030	Total
Volume – Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Solar	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
Volume – Baker Hughes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Baker Hughes				[redacted]		[redacted]
Volume – Warranty	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Cost – Warranty		[redacted]	[redacted]		[redacted]	[redacted]
Total (volume)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total (cost)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Varnish removal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total opex	**4,156**	**7,406**	**7,406**	**6,160**	**7,406**	**32,534**

1.5.3.3 Risk assessment

Table 1.13 shows that this option does moderate the threat, the frequency and/or the consequence to reduce the overall risk rank to intermediate or lower.

Table 1.13: Risk rating impact - Option 3

Risk category	Untreated	Treated
People	Intermediate	Negligible
Environmental	Low	Negligible
Supply	Intermediate	Low
DBP	Intermediate	Low
Reputation	Low	Negligible
Loss	Intermediate	Low

This option reduces the inherent risk of these failure of gas turbines to ALARP with planned overhauls in line with manufacturers' guidelines to ensure assets are available and can support our ability to deliver gas safely and reliably to meet the needs of our customers and gas producers.

The risks associated with this option are lower than option 2, since if two premature failures were to occur, we would not need to reprioritise our works program to defer planned overhauls where turbines are at or exceeding the maximum run times. However, we expect we will be able to manage with the third failed unit for a short period of time by changing our operational strategy. This, however, would increase our overhaul expenditure in AA7.

1.6 Summary of cost/benefit assessment

To assess the options, the costs, objectives and risk are considered for each option. A summary of the option assessment is shown in Table 1.14.

Table 1.14: Summary of cost/benefit analysis

Option	Achievement of objectives	Cost	Treated risk (integrity/reliability)
Option 1 – Replace on failure	This option does not achieve our objective of delivering for customers and being a good employer but is not sustainably cost efficient	No upfront cost	This option does not treat the identified risk at all.
Option 2 – Proactive overhaul based on runtimes and two premature failures	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$29.3 million	This option appropriately moderates all high/intermediate risks to ALARP
Option 3 – Proactive overhaul based on runtimes and three premature failures	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$32.5 million	This option appropriately moderates all high/intermediate risks to ALARP

1.7 Proposed solution

1.7.1 Why is the recommended option prudent?

The recommended option is Option 2. The proactive overhaul of gas turbines based on the runtimes is consistent with the volume and activities the AMP has identified as required to appropriately mitigate the risk identified under our Operational Risk Framework and manages the asset consistent with asset management principles and the relevant original equipment manufacturers' specification.

Option 2 was considered based on the number of premature failures experienced in AA5 and the continued aging of our gas turbines. However, we consider it might be prudent to look to change our operations to defer one overhaul to the next period should we need to manage within our forecast expenditure in the period. Should we consider the risk associated with a deferral is too high (should the need for an overhaul occur), we would of course undertake the necessary works in excess of the value of our allowance.

Running the assets to failure as per option 1 is likely to result in catastrophic failure of an asset which gives rise to significant safety risk, significant additional costs and significant adverse impact on the service provided to customers. It could also give rise to penalties and reputational damage should a failure result in an inability to meet customer capacity demands.

1.7.2 Estimating the efficient costs

As noted in the 'Final Plan Attachment 8.7_Cost Estimation Methodology 2026-2030', the unit rates used for all projects managed within this program include the forecast internal labour, external labour/contractors, materials, travel and other costs.

For AA6, the unit costs for gas turbine overhauls been estimated based on the most recent historical cost incurred for the same or a similar program of work, with $[redacted].

Key assumptions which have been made in the cost estimation for gas turbine overhauls are as follows:

- Forecast rates for AUD equivalent costs of USD sourced equipment items are based on the [redacted], reflecting recent exchange rates.
- [redacted] of the overhauls will be [redacted] and [redacted] will be a [redacted]
- [redacted] will occur under the manufacturer's warranty.
- The price differential between [redacted] remain unchanged relative to the most recent overhauls completed, with the difference driven by the relative costs of the equipment.
- Internal costs are unchanged from recent actual costs incurred.

Specialist engineering, procurement and construction management (EPCM) activities are provided utilising internal resources, supplemented by external specialist input as required. Delivery of the work is primarily through external resources. This is the model that has been successfully deployed and implemented on the DBNGP for AA5 and previous AAs.

1.7.3 Consistency with the National Gas Rules

Proactive overhaul of gas turbines maintains the safety, integrity and reliable delivery of gas along the DBNGP by ensuring gas turbine units are available as required to meet customer demand.

Proactively overhauling, in line with manufacturer recommendations and over 35 years of operational experience, ensures these assets continue to perform efficiently and represents a more cost-effective solution over the life of the asset than full replacement. Therefore, it is consistent with the expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Rule 91

The relevant opex rule is detailed below and has been extracted from the latest version of the National Gas Rules (available here: http://www.aemc.gov.au/energy-rules/national-gas-rules/current-rules):

> *"Division 7 Operating expenditure*
>
> *91 Criteria governing operating expenditure*
>
> *(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.*
>
> *(2) The AER's discretion under this rule is limited."*

Option 2 – 'Proactive overhaul based on runtimes and one premature failure' is the recommended solution and recommends that we proceed with the overhaul of the gas turbines in line with AMP and manufacturers' guidelines.

Proactive overhaul based on the AMP is consistent with the requirements of NGR 91(1), specifically the proposed expenditure is:

- **Prudent** – Proactive overhaul of gas turbines maintains the safety, integrity and reliable delivery of gas along the DBNGP by ensuring gas turbine units are available as required to meet customer demand. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- **Efficient** – Our forecasts for when overhauls will fall due is based on the latest information on run hours, utilisation and expected throughput. The forecast cost per overhaul is based on the historical costs of similar recent works and current prevailing foreign exchange rates. Proactively overhauling represents a more cost-effective solution over the life of the asset than full replacement. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed overhaul activity follows good industry practice of aligning overhauls with commitments embedded within the AMP and manufacturer's recommendations.
- Required to achieve **the lowest sustainable cost of delivering pipeline services** – Undertaking the overhaul program in a proactive, planned and scheduled manner based on run hours forecast reduces total costs over the life of these assets, where unplanned failure could lead to damage requiring full replacement. Our contractual arrangements with the OEM are managed in line with our procurement policy to ensure the best commercial terms can be achieved.

NGR 74

Our forecasts for gas turbine overhauls are based on the latest information on run hours, utilisation and expected throughput and are consistent with OEM specifications. The forecast cost per overhaul is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

The proposed volume and timing of activity is guided by our asset management plans and has regard to our regulatory obligations, manufacturer's recommendations, and Australian and International Standards. The work will be delivered by a mix of internal and external resources. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimisation with other programs of work where possible. The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with the NGR.

1.7.4 Justification of non-base year cost

The preventative maintenance overhaul program for gas turbines is influenced not by financial or regulatory periods, but by the pace with which these assets' useful lives are consumed.

The use of a base year would not take into consideration the core driver for this activity – run hours in operational use - or the impact an arbitrary overhaul volume selection could have on the broader health and reliability of the pipeline or risk profile of the individual asset.

The operational use of these assets is not uniform across units, so each one needs to be considered individually based on its current and forecast run hours. The forecast activity is reviewed on a monthly basis, as external changes such as customer demands, weather and the 'transfer' of operational load to alternative assets is considered and overhaul dates adjusted accordingly.

There is a large variation of annual hours across these assets, and analysis of these hours is considered a key input into the identification of assets requiring overhaul in AA6.

1.8 Comparison to previous periods

1.8.1 AA6 forecast compared to AA5

In AA6, capital expenditure of $28.4 million is forecast for the turbine exhaust replacement program. Table 1.15 shows the forecast AA6 expenditure compared with actual expenditure in AA5. Our AA6 forecast is largely in line with our AA5 actual spend.

Table 1.15: AA5 forecast operating expenditure, compared with AA5 actual ($'000)

Forecast spend ($'000)	2026	2027	2028	2029	2030	AA6	AA5 total	Variance
Operating expenditure	4,156	7,406	4,156	6,160	7,406	**29,284**	**29,786**	**-502**

1.8.2 AA5 variance

Actual expenditure during the AA5 period is forecast to be $5.1 million higher than the amount determined in the AA5 Final Decision.

Table 1.13: AA5 actual expenditure compared with budget

Actual v budget ($'000, Dec2024)	2021	2022	2023	2024	2025	AA5
AA5 actual	6,750	9,705	8,829	3,793	708	29,786
AA5 approved	9,076	7,202	7,207	-	1,220	24,705
Variance	**-2,326**	**2,503**	**1,622**	**3,793**	**-512**	**5,080**

The above forecast spend relates to the number of replacements required being consistent with our forecast rather than the ERA's reduced volumes. This was exacerbated by the increased cost per unit related to the reactive nature of the works, and the impact of the COVID-19 pandemic.

Appendix A Comparison of risk assessments

Table A1: Summary of risk assessment

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP05	Turbine overhauls	Failure of engines due to excessive run hour usage leading to unavailability of engine, engine damage as well as potential safety impact where failure involves fragmentation of internal components	Untreated Risk	Likelihood	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
				Consequence	Major	Minor	Severe	Severe	Minor	Severe
				Risk Level	INTERMEDIATE	LOW	INTERMEDIATE	INTERMEDIATE	LOW	INTERMEDIATE
			Option 1 – Move to a replacement on failure policy	Likelihood	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
				Consequence	Major	Minor	Severe	Severe	Minor	Severe
				Risk Level	INTERMEDIATE	LOW	INTERMEDIATE	INTERMEDIATE	LOW	INTERMEDIATE
			Option 2 – Proactive overhaul based on expected runtimes and two premature failures	Likelihood	Hypothetical	Hypothetical	Remote	Remote	Remote	Remote
				Consequence	Trivial	Trivial	Severe	Severe	Minor	Severe
				Risk Level	NEGLIGIBLE	NEGLIGIBLE	LOW	LOW	NEGLIGIBLE	LOW
			Option 3 – Proactive overhaul based on expected runtimes and three premature failure	Likelihood	Hypothetical	Hypothetical	Remote	Remote	Remote	Remote
				Consequence	Trivial	Trivial	Severe	Severe	Minor	Severe
				Risk Level	NEGLIGIBLE	NEGLIGIBLE	LOW	LOW	NEGLIGIBLE	LOW

1 Opex DBP04: Health, safety and environment

1.1 Project approvals

Table 1.1: DBP04 Health, safety and environment – Project approvals

Prepared by	John Wilson, Head of Health & Safety Transmission
Reviewed by	Jeff Kong, Head of Asset Strategy
Approved by	Tawake Rakai, GM Transmission Asset Management

1.1 Project overview

Table 1.2: DBP04 Health, safety and environment – Project overview

<table>
<tr><td>Description of problem /opportunity</td><td>Ongoing improvements in our health, safety and environment (HSE) outcomes are critical. They are required to keep our staff and the public safe in a constantly changing environment.
Continued investment in HSE improvement projects is necessary to meet our vision, our workplace health and safety obligations, as well as our Safety Case.
Our focus, without compromise, is Zero Harm to enable all our employees to return home safe.
Our safety programs are shared and reported to our people, our owners and our regulators.
We have a number of planned projects for the AA6 period, but also have included an allowance to address HSE issues as they arise during the period.</td></tr>
<tr><td>Untreated risk</td><td>As per risk matrix = Intermediate</td></tr>
<tr><td>Options considered</td><td>Option 1 – Allow for HSE initiatives at historical average levels ($0.64 million)
Option 2 – Allow for BAU HSE initiatives at historical average levels plus a major HSE initiative essential for staff and public safety ($0.98 million) (this is the recommended option)
Option 3 – Do not improve HSE outcomes (no upfront costs)</td></tr>
<tr><td>Proposed solution</td><td>We forecast a program of works in line with the historical average spend on HSE initiatives from the AA5 period. This includes the following types of initiatives:
Ergonomics
Permit to work training
Leadership in safety
Noise surveys and management activities</td></tr>
<tr><td>Estimated cost</td><td>The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $983,000.<table><tr><th></th><th></th><th></th><th></th><th></th><th></th><th></th></tr><tr><td>Total</td><td>301</td><td>301</td><td>127</td><td>127</td><td>127</td><td>983</td></tr></table></td></tr>
<tr><td>Basis of costs</td><td>All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.</td></tr>
</table>

Treated risk	As per risk matrix = Low
Variation from AA5	The forecast expenditure for AA6 is consistent with the forecast expenditure in AA5 of $934,000. In 2024 we undertook an arc flash survey on assets between compressor stations 1 and 7 to ensure we remain compliant with AS4836 following its revision in 2023. This one-off study was not anticipated, and increased our HSE spend by around $300,000.
Alignment to our vision	This option delivers against all of our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it ensures we can maintain our safety culture and continue to meet the HSE standards driven through our business externally and internally.
Consistency with the National Gas Rules (NGR)	This project complies with the following National Gas Rules (NGR): **NGR 91** – Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. The continued expenditure on HSE improvement projects is necessary from a regulatory perspective to meet our workplace health and safety obligations, and Safety Case. Continued assessment of, and investment in improving our HSE processes, systems and practices is critical to keeping our staff and the public safe. The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with Rule 91. **NGR 74(2)** – Our forecasts for HSE are based on the continuation of HSE activities that are critical to the safety of our staff and the public such as noise surveys, but also allow us to address any issues/risks we identify through the period. The forecast cost per project is based on historical actual costs, with the anomalous expenditures excluded. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.
Stakeholder engagement	Our shippers told us they highly value current levels of reliability and would be concerned if this were to change. They also expect us to maintain a strong focus on operational issues as it is important for reliability and emergency management. Our HSE program is important to ensure that our staff and the public are continued to be kept as safe as they can be.
Other relevant documents	This business case should be read in conjunction with: • Asset Management Plan (TEB-001-0024-07) • Risk Management Policy and Operational Risk Model (together our Risk Management Framework) • AGIG Zero Harm Standards

1.2 Background

We are committed to ensure we offer a safe working environment that not only meets regulatory requirements but also internal safety expectations in terms of physical and mental health needs of employees. Our ongoing health and safety program delivers initiatives to support the health and safety of our employees and contractors who work along or near the pipeline. Our environmental program focuses on compliance, ensuring that updates are rolled out as needed to reflect changes to regulatory or reporting requirements which are often driven by external changes.

In each regulatory period we include in our opex forecast an allowance to sustain our ongoing HSE program. The majority of the HSE work is recurrent in nature, however we typically include in our forecasts an allowance for one-off major HSE initiatives that may arise during the five-year regulatory period.

For example, during the AA5 period we saw legislative changes to safety around low voltage electrical equipment drive a major project to understand issues around arc flashing. In response we undertook an arc flash survey on assets between compressor stations 1 and 7 to ensure we remain compliant with AS4836 following its revision in 2023. This unforeseen requirement added approximately $300k to our expenditure during the period.

For the AA6 period, we have included HSE costs to improve our monitoring of Volatile Organic Compounds (VOC) and BTEX (Benzene, Toluene, Ethyl-Benzene Xylene) at each of our compressor stations along the pipeline. Though not an unforeseen initiative, it represents a new one-off (non-recurrent) initiative that we must include in our HSE opex forecast.

The VOC and BTEX initiative is required to ensure our staff and the public are safe, there is no major impact on the environment and we are compliant with requirements under the *Environmental Protection Act* and associated regulations. It will also help us report better data for the National Pollutant Inventory[1].

1.3 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, as shown below in Figure 1.1 with a commitment to balance outcomes sought with delivery and cost implications considered and assessed.

Figure 1.1: Risk management principles

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible.

[1] The National Pollutant Inventory (NPI) in Australia is a database that provides information about the emissions of 93 toxic substances from various industrial facilities across the country. It is a collaborative effort between the Australian Government and state and territory governments. The NPI requires reporting of emissions which is made publicly available, and is used to monitor and understand pollution sources and help identify pollution trends and priorities for environmental protection efforts.

The risk rating assesses the consequence and likelihood of the risk. The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS 2885 and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Modify the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

Six areas are considered for each type of risk:

1. DBP – corporate/financial risk
2. People – safety risk to the public and employees
3. Environmental – risk of adverse impact on environment/local ecosystems
4. Reputation/Outrage – risk of customer anger and reputational damage
5. Asset Damage – dollar impact on assets
6. Supply – risk of supply interruption to customers

The primary risk event that applies to HSE is a lack of continuous HSE and training improvement and inadequate level of compliance with some legislation relating to management of HSE impacting on DBP reputation, safety and employee engagement.

The overall risk rating of HSE is presented in Figure 1.2. Three elements of risk are rated as intermediate, two low and one negligible. This results in an intermediate risk ranking for these assets in an untreated scenario.

Figure 1.2: Untreated risk rating

	Trivial	**Minor**	**Severe**	**Major**	**Catastrophic**
Frequent		DBP			
Occasional			People Reputation		
Unlikely		Environmental			
Remote					
Hypothetical	Supply Loss				
	Negligible	**Low**	**Intermediate**	**High**	**Extreme**

HSE initiatives are intermediate risk but high priority as they relate to the safety of our people, the public and the environment. The overall risk rating of not undertaking HSE initiatives is identified as intermediate in Figure 1.5.

Specific drivers of this risk rating are:

- **People** – Untreated, there are safety risks that we know about that are going unaddressed. This will result in occasional safety incidents that could potentially severely impact one or more of our staff or the public. Our injury KPIs would increase and we would see a higher staff turnover rate.
- **DBP** – Without proactive investment in providing a safe workplace for our staff and addressing safety and environmental outcomes for the public, we would likely be unable to attract and retain an adequately skilled workforce. This would become problematic for pipeline operations and DBP over the long term.
- **Reputation** – With known risks going untreated, and occasional sever injury of our staff or the public it is likely to attract sustained negative national media attention. As safety of our pipeline assets and operations is the highest priority this is unacceptable.

1.4 Options considered

Different options have been considered to ensure our assets are managed in a safe manner when they become obsolete or redundant. The options are:

- Option 1 – Allow for BAU HSE initiatives at historical average levels
- Option 2 – Allow for BAU HSE initiatives at historical average levels, plus one major initiative essential to ensure staff and public safety
- Option 3 – Do not improve HSE outcomes

The options are discussed in the/ following sections.

1.4.1 Option 1 – Allow for BAU HSE initiatives at historical average levels

Under this option we would continue undertaking planned HSE activities at the same rate as our business as usual program ($127,000 per annum). This would allow us to continue our regular program of activities such as:

- Ergonomics
- Permit to work training
- Leadership in safety
- Noise surveys and management activities

However, it would not allow for new major HSE activities such as the VOC and BTEX monitoring project identified for the AA6 period. We would need to accommodate this by deferring other less critical work.

1.4.1.1 Achievement of objectives

Table 1.3 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.3: Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

This option delivers against all of our vision objectives of delivering for customers, being a good employer. However, it would not accommodate the known VOC and BTEX project identified as required in AA6. To undertake this project we would need to reprioritise our budget.

1.4.1.2 Cost assessment

The forecast opex under this option is $635,000 for the AA6 period at $127,000 per annum. This estimate is based on the average actual per annum AA5 cost excluding the arc study project.

1.4.1.3 Risk assessment

Table 1.4 shows that this option does 'moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

Table 1.4: Risk assessment - Option 1

Risk category	Untreated	Treated
People	Intermediate	Low
Environmental	Low	Negligible
Supply	Negligible	Negligible
DBP	Intermediate	Negligible
Reputation / outrage	Intermediate	Low
Loss	Negligible	Negligible

This option reduces the overall risk exposure in each risk category by proactively addressing our high priority HSE risks but it is not as low as reasonably practicable (ALARP).

1.4.2 Option 2 – Allow for BAU HSE initiatives at historical average levels and a major project

This option is the same as option 1, but it would also allow for a major HSE project such as the arc flash study we did in 2024 and the identified VOC and BTEX monitoring project without having to defer other work.

1.4.2.1 Achievement of objectives

Table 1.5 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.5 Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	Y
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

This option delivers against all of our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it addresses known HSE risks and issues as they arise.

1.4.2.2 Cost assessment

The forecast opex under this option is $983,000 for the AA6 period. This estimate is aligned with the average actual per annum cost during AA5 including the arc study project which is expected to be a similar size to the VOC and BTEX monitoring project.

Table 1.6: Forecast opex – Option 2

$,000, Dec24	2026	2027	2028	2029	2030	Total
BAU HSE	127	127	127	127	127	**635**
VOC and BTEX monitoring	174	174	-	-	-	**348**
Total	**301**	**301**	**127**	**127**	**127**	**983**

1.4.2.3 Risk assessment

Table 1.7 shows that this option does 'moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

Table 1.7: Risk assessment - Option 2

Risk category	Untreated	Treated
People	Intermediate	Low
Environmental	Low	Negligible
Supply	Negligible	Negligible
DBP	Intermediate	Negligible
Reputation / outrage	Intermediate	Low
Asset damage / Loss	Negligible	Negligible

This option is ALARP and reduces the overall risk exposure in each risk category by proactively addressing our high priority HSE risks as they arise.

1.4.3 Option 3 – Do not improve HSE outcomes

Under this option, no proactive HSE initiatives would be undertaken in AA6.

1.4.3.1 Achievement of objectives

Table 1.8 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.8: Achieving objectives - Option 3

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

This option does not deliver against relevant vision objectives of being a good employer and being sustainably cost efficient as it would not invest in HSE initiatives driven by internal commitments to health, safety and well-being or employees and would also fail to support the business in delivering on regulatory requirements in the event of a new requirement being introduced in the next five years.

1.4.3.2 Cost assessment

There is no upfront cost associated with this option.

1.4.3.3 Risk assessment

This option does not change the risk rating from the untreated scenario.

1.5 Summary of cost/benefit assessment

To assess the options, the costs, objectives and risk are considered for each option. A summary of the option assessment is shown in the following table.

Table 1.9: Summary of options

Option	Achievement of objectives	Cost	Treated risk
Option 1: Allow for BAU HSE initiatives at historical average levels	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$635,000	Addresses the intermediate risks to DBP / People/ Reputation but it is not ALARP
Option 2: Allow for BAU HSE initiatives at historical average levels and a major project essential for staff and public safety	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$983,000	Addresses the intermediate risks to DBP / People/ Reputation and is ALARP
Option 3: Do not improve HSE outcomes	This option does not achieve our objectives of delivering for customers, being a good employer or being sustainably cost efficient	No upfront cost	This option does not address any of the risks and are therefore left untreated

1.6 Proposed solution

1.6.1 Why is the recommended option prudent?

The recommended option is to continue to undertake a 'business as usual' level of HSE works and undertake the essential VOC and BTEX monitoring project to improve safety outcomes for our staff and the public, and environmental outcomes. It aligns with our Risk Management Framework, asset management principles, vision objectives and regulatory requirements including the Safety Case.

Option 1 would not provide additional opex to allow us to undertake the monitoring project. As shown in AA5 having insufficient funding would not prevent us from doing this project as it is necessary. We would therefore need to reprioritise our budget and forgo another opex project in the AA6 period. This could increase risk elsewhere, and could have other implications including financial, reputation and operations.

Option 3 provides no improvement in risk rating from the untreated scenario.

1.6.2 Estimating the efficient costs

The costs are estimated by rolling forward the average actual costs from AA5.

As noted in the 'Final Plan Attachment 8.7 Cost Estimation Methodology 2026-2030', the forecast unit rates for all projects/initiatives managed within this program are inclusive of internal labour, external labour/contractors, materials, travel and other costs.

1.6.3 Consistency with the National Gas Rules

Option 2 is the preferred solution and ensures the safety of our staff, the public and the environment will continue to be maintained with all identified issues addressed in a timely manner. It is consistent with our Safety Case and the expectations of our organisation both internally and externally.

NGR 91

NGR 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Specifically, the proposed HSE expenditure is:

- **Prudent** – Undertaking proactive HSE activities in line with the industry standards and is critical to maintain the safety, integrity and reliable delivery of gas along the DBNGP by minimising the risk of safety related incidents affecting our staff or the public. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- **Efficient** – We consider several options to treat HSE risks. This includes modifications to or new systems, processes and practices. The forecast is based on historical average annual costs from the current period. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed HSE program follows good industry practice and is consistent with our Safety Case and relevant workplace health and safety legislation.
- Required to achieve **the lowest sustainable cost of delivering pipeline services** – Looking after our skilled staff reduces the total costs of providing pipeline services as it reduces turnover and the costs associated with onboarding and upskilling new staff.

NGR 74(2)

Our forecasts for HSE activities are based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

1.7 Comparison to previous periods

1.7.1 AA6 forecast compared to AA5

In AA6, operating expenditure of $983,000 is forecast for the HSE program. Table 1.10 shows the forecast AA6 expenditure compared with actual expenditure in AA5.

Table 1.10: AA5 forecast capital expenditure, compared with AA5 actual ($'000, Dec24)

Forecast spend ($'000)	2026	2027	2028	2029	2030	AA6	AA5 total	Variance
HSE	301	301	127	127	127	**983**	**934**	**49**

1.7.2 AA5 variance

Actual expenditure during the AA5 period was $384,000 higher than the amount determined in the AA5 Final Decision.

Table 1.11: AA5 actual expenditure compared with budget

Actual v budget ($'000)	2021	2022	2023	2024	2025	AA5
AA5 actual	102	162	115	465	90	**934**
AA5 approved	110	110	110	110	110	**550**
Variance	**-8**	**52**	**5**	**355**	**-20**	**384**

The higher expenditure is the result of an unforeseen major HSE project undertaken in AA5. In 2023, AS 4836: Safe working on or near low-voltage electrical installations and equipment in 2023 was revised which resulted in a change to the definition, and more information related to hazard risk assessments and the personal protective equipment that should be used. In 2024, we undertook an arc flashing study on our assets between compressor station one and seven to ensure we remain compliant with the revised standard.

Appendix A Comparison of risk assessments

Figure A.1: Summary of risk assessment

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP04	Health, safety and environment	Lack of continous HSE and training improvement and inadequate level of compliance with some legislation relating to management of HSE impacting on DBP reputation, safety and employee engagement.	Untreated Risk	Likelihood	Occasional	Unlikely	Hypothetical	Frequent	Occasional	Hypothetical
				Consequence	Severe	Minor	Trivial	Minor	Severe	Trivial
				Risk Level	INTERMEDIATE	LOW	NEGLIGIBLE	INTERMEDIATE	INTERMEDIATE	NEGLIGIBLE
			Option 1 – Allow for HSE initiatives at historical average levels ($0.64 million)	Likelihood	Unlikely	Unlikely	Hypothetical	Unlikely	Unlikely	Hypothetical
				Consequence	Severe	Minor	Trivial	Minor	Severe	Trivial
				Risk Level	INTERMEDIATE	LOW	NEGLIGIBLE	LOW	INTERMEDIATE	NEGLIGIBLE
			Option 2 – Allow for BAU HSE initiatives at historical average levels plus a major HSE initiative ($0.98 million)	Likelihood	Remote	Unlikely	Hypothetical	Unlikely	Remote	Hypothetical
				Consequence	Severe	Minor	Trivial	Minor	Severe	Trivial
				Risk Level	LOW	LOW	NEGLIGIBLE	LOW	LOW	NEGLIGIBLE
			Option 3 – Do not improve HSE outcomes (no upfront costs)	Likelihood	Occasional	Unlikely	Hypothetical	Frequent	Occasional	Hypothetical
				Consequence	Severe	Minor	Trivial	Minor	Severe	Trivial
				Risk Level	INTERMEDIATE	LOW	NEGLIGIBLE	INTERMEDIATE	INTERMEDIATE	NEGLIGIBLE

1 Opex DBP13: Station inspections

1.1 Project approvals

Table 1.1: DBP13 Station inspections – Project approvals

Prepared by	Andrew Stanwix, Principal Engineer Mechanical C&P RE
Reviewed by	Jeff Kong, Head of Transmission Asset Strategy, AGIG
Approved by	Tawake Rakai, GM Transmission Asset Management, AGIG

1.2 Project overview

Table 1.2: DBP13 Station inspections – Project overview

Description of problem /opportunity	Compressor stations and meter stations are critical assets along the DBNGP. These stations are subject to an ongoing inspection regime. The core inspection activities for the station inspections program are: • Mandatory inspection of pressure vessels (including water bath heaters); • Mandatory inspection of pressure relief valves; and • Inspection and re-preservation of compressor rotor bundles in long term storage. These are inspected as per the requirements of Australian Standard 3788 (AS 3788) and the asset management requirements under AS 2885. We have a well-established inspection routine for pressure vessel and relief valve inspections and propose to continue this throughout the AA6 period along with the inspection and re-preservation of stored compressor bundles. Our meter and compressor station sites contain a range of other assets such as exhausts, vent attenuators and site buildings, as well as the land itself. Inspection of these assets has historically been ad-hoc in nature, addressing issues reactively when identified but not formally built into our proactive inspection program. Our aim for AA6 is to take a more proactive approach to monitoring these additional compressor and meter station assets, factoring them into our routine pressure vessel and relief valve inspection regime.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Maintain compliance inspection obligations of pressure vessel, relief valves and compressor rotor bundles ($7.8 million) • **Option 2 –** Expand the inspection program to cover additional mechanical/rotational assets, structures and site contamination ($8.7 million)
Proposed solution	The proposed solution is Option 2. The frequency of these inspections is directed by the requirements of AS 3788, however, additional inspections occur where the condition of the assets requires it. Further inspections will be carried out at DBP stations in line with good proactive asset management practices, which include vent attenuators, site buildings and contamination. The cost estimate is based on identifying the number of inspections required and the appropriate unit cost of each. The unit cost will vary for different inspection types based on whether it is for a compressor station or meter station and where it is located.
Estimated cost	The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $8.7 million (2024).

	$'000 real Dec2024	2026	2027	2028	2029	2030	Total
	Total	1,772	1,729	2,029	1472	1,656	**8,660**

Basis of costs	All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.
Treated risk	As per risk matrix = Intermediate
Variation from AA5	The forecast expenditure for AA6 is $3.2 million more than the estimated expenditure in AA5 of $5.5 million. The increase in AA6 is largely the result of: • Higher inspection costs due to post-pandemic increases in labour and material costs, coupled with changes to inspection practices. • The inclusion of additional structure, vent and contamination inspections on compressor and meter stations to better inform future asset management strategies.
Alignment to our vision	Delivering the ongoing stations inspection program aligns with AGIG's vision in relation to: • *Delivering for customers* – The continued stations inspection program delivers for customers in terms of public safety and reliability. Maintaining and investing in our pipeline assets is critical to ensure supply for our customers. By completing inspections on a cycle, we can prevent corrosion or asset failures of the assets to improve our public safety and network integrity management capabilities, minimising the likelihood of uncontrolled gas escapes and extended outages. • *A Good Employer* – The continued stations inspection program ensures the health and safety of our employees and contractors working across the pipeline assets by having reliable, accurate information in relation to asset condition. • *Sustainably Cost Efficient* – The inspection of our stations assets in compliance with Australian Standards for inspections, and without impact to pipeline operations, ensures we are maintaining our assets in the most cost effective and efficient manner and working within industry benchmarks.
Consistency with the National Gas Rules (NGR)	National Gas Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. Pressure vessels and pressure release valves are high risk assets which are important in maintaining the safety, integrity and reliable delivery of gas along the DBNGP. The performance of these assets can be proactively managed through inspection to ensure early intervention as needed, in accordance with AS 3788 guidelines. The need to address these assets is based on the latest information available resulting from previous inspections, and ongoing assessment of the most appropriate inspection methodology ensures consistency with rule 74 (2) which requires the forecast to be (a) arrived at on a reasonable basis; and (b) represent the best forecast or estimate possible in the circumstances is also achieved. The cost of each inspection type is based on historical actual cost, which reflects commercially negotiated unit rates that have been market tested, in line with our Procurement Policy and Purchasing Procedure.
Stakeholder engagement	Our Shippers advised they highly value current levels of reliability and would be concerned if this were to change. They also expect us to maintain a strong focus on operational issues as it is important for reliability and emergency

	management. Our compressor and meter station inspection program is a proactive maintenance activity to ensure the long term integrity of our assets. During Shipper Roundtables, we presented key areas of planning, including our proposed capex and opex. Our proposed approach was then outlined in the Draft Plan. No questions were specifically raised in relation to the station inspections program. In response to Shippers' general interest in how we deal with changing business needs during an AA period, this business case outlines what changes in approach have been considered and will be implemented in our AA6 program of work.
Other relevant documents	This Business Case should be read in conjunction with: • Asset Management Plan (TEB-001-0024-07); • Asset Management Plan – Rotating Equipment (TEB-001-0024-03); • DBP19 – Pipeline and MLV inspections; and • Risk Management Policy and Operational Risk Model (together our Risk Management Framework).

1.3 Background

All physical DBNGP assets are managed in accordance with the policies and principles set out in our asset management system framework. A key principle of the asset management system framework is effective management of asset risks, which includes identification of risks and evaluation of the adequacy of controls in terms of physical safeguards and asset maintenance requirements.

The compressor and meter station inspections program is an essential part of the asset management framework, helping us monitor the condition and performance of critical pipeline assets. The proactive inspection program has focused historically on pressure vessels (including water bath heaters) and pressure relief valves. Both these assets contain gas/liquids at very high pressures and have the potential to cause significant harm and service disruption if they fail. As such, we have a regulatory obligation to inspect pressure vessels and relief valves as per the requirements of AS 3788.

We have a well-established inspection routine for pressure vessel and relief valve inspections and propose to continue this throughout the AA6 period. Note the ongoing pressure vessel and relief valve program costs are increasing in AA6 compared with the AA5 period due to increased labour and equipment costs (in the wake of the global pandemic) as well as changes to inspection practices.

As part of our AS 3788 requirements we also inspect and re-preserve compressor rotor bundles that are in long term storage at our Jandakot facility. These rotor bundles are high value, high risk assets that are integral to station operation. It is essential our stored spares are in good condition, so that we can swap them out quickly if and when installed compressor bundles fail or fall due for replacement.

Our compressor and meter station sites contain a range of other assets such as exhausts, vent attenuators and site buildings, as well as the land itself. Inspection of these assets has been transitioned to a more coordinated and planned program to ensure risks that emerge from our operations are proactively managed.

Our aim for AA6 is to be more proactive in monitoring these additional asset risk issues and to factor them into our routine pressure vessel and relief valve inspection routine. A driver for this expanded proactive inspection regime is recent testing for hydrocarbons in the soil at CS8. The site is being re-mediated and has prompted the need for similar inspection programs at all meter and compressor stations.

Adding these asset risks into our pressure vessel/relief valve/compressor bundle inspection regime is relatively low cost, driving an incremental increase of around [redacted] per year compared to the standard inspection program. Most importantly, this expanded inspection program will allow us to get ahead of emerging meter station and compressor station site issues, such as land contamination, building dilapidation, and wear and tear on other mechanical/rotational assets.

1.3.1 Core inspection program

The core inspection activities for the station inspections program are:

- Mandatory inspection of pressure vessels (including water bath heaters);
- Mandatory inspection of pressure relief valves; and
- Inspection and re-preservation of compressor bundles in long term storage.

The frequency of inspections vary depending on the asset that is being inspected.

The nominal inspection intervals stipulated in AS 3788 are generic in order to address a wide range of industries, applications and process conditions. As such, and in light of the relatively mild environments to which our pressure vessels are subjected (clean, dry natural gas at moderate temperatures), the intervals are believed to be conservative for DBP's application.

AS 3788 allows for a risk based inspection process to be adopted whereby the inspection frequency can be altered based on a thorough understanding of the level of risk and the controls involved. This allowance is made available based on accurate inspection and maintenance history and a thorough understanding of the likely modes of failure.

We leverage historical information and all other knowns to determine the optimal inspection frequency. An audit of our inspection regime in 2022 found no deficiencies in our volume of inspections, however, two administrative areas of improvement were identified and shall be addressed through an improved Integrated Data Management System (IDMS), which has been implemented during the AA5 period. The IDMS will ensure easy access, interrogation and usability of data collected in managing the integrity and process safety of these assets.

We therefore propose to maintain a similar inspection regime for pressure vessels, relief valves and compressor bundles in long term storage, as was applied during the AA5 period.

It should be noted that costs for this ongoing inspection regime have increased over the AA5 period and is primarily due to higher labour and equipment costs, which are being felt across the industry. Water bath heater inspections, in particular, have increased due to the specialist nature of the work.

There have also been changes to inspection practices over the AA5 period. For example, the inspection routine now includes high pressure clearing of heater internals during inspection, storage and disposal of waste fluids, and biocide dosing. These activities were not included in the AA4 and AA5 works scope.

1.3.2 Expanded inspection program

The inspection program for the AA6 period will be expanded to cover proactive inspection of additional site assets including:

- Structural inspection of buildings and assemblies that house and support assets.
- Gas engine/compressor exhaust and air inlet inspections.
- Vent attenuator inspections.
- Land contamination.

We have begun expanding our inspections to cover these additional assets towards the end of the AA5 period and propose to continue this more thorough inspection program during AA6.

Where practicable, the inspection of buildings, exhausts, air inlets and vent attenuators will be conducted concurrently with the ongoing pressure vessel and relief valve inspections. However, the land contamination inspections will run independently of the other inspections due to its different specialised skill set. The inspections and management of contaminated land will align with Australian Standard AS 4482.1-20051.

The proposed inspection profile for the AA6 period is shown in Table 1.3.

Table 1.3: AA5 station inspections – units and cost for core and expanded inspection program ($Dec24)

Inspection type	AA6 units 2026	2027	2028	2029	2030	Total units	Total cost ($,000)
Compressor sites							
Pressure vessels	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,125**
Pressure relief valves	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,955**
Structural & vent attenuators	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**175**
Exhaust/air inlet	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**411**
Compressor bundles	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		**35**
Meter stations							
Pressure vessels	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**3,140**
Pressure relief valves	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,429**
Structural & vent attenuators	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**207**
All sites							
Contamination	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**185**
						Total cost ($,000)	**8,660**

Further information on the proposed inspection regime is provided in Appendix B.

1.4 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, with a commitment to balance outcomes sought with delivery and cost implications considered and assessed.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Figure 1.1: Risk management principles

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible. The risk rating assesses the consequence and likelihood of the risk.

The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS 2885 and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

Six areas are considered for each type of risk:

1. People – injuries or illness to employees and contractors or members of the public
2. Environmental impact – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Supply – disruption in the provision of services/supply, impacting customers
4. Impact on AGIG/DBP – impact on AGIG (DBP) due to restrictions and enforcement, such as regulatory enforcement or legal actions
5. Reputation – impact on stakeholders' views of AGIG (DBP), including personnel, customers, investors, security holders, regulators and the community
6. Loss – financial impact on AGIG (DBP)

The primary risk event associated with pressure vessels and release valves is failure resulting in loss of containment, inability to protect pressure containing vessel in process upset conditions or structural failure, all of which could lead to fatal injuries as a result of not performing mandatory fit for purpose inspections and testing.

The overall risk rating is presented below. Two elements of risk are rated as high, three intermediate risk and one low. This results in a high risk ranking for these assets in an untreated scenario.

Figure 1.2: Risk rating – station inspections

	Trivial	Minor	Severe	Major	Catastrophic
Frequent					
Occasional					
Unlikely		Environmental	Supply Reputation Loss	DBP	
Remote					People
Hypothetical					

Negligible	**Low**	**Intermediate**	**High**	**Extreme**

The drivers of the risk intermediate and high-risk ratings are discussed below.

- **DBP** – Untreated, the pressure vessels and pressure relief valves would threaten the effective operation of DBP for a substantial period, including its ability to raise capital, or have a significant effect on how DBP will operate in the future.
- **People** – Untreated, pressure vessels and pressure relief valves could result in more than two fatalities or more than four individuals with life threatening injuries or permanent disabilities.
- **Reputation** – Untreated, pressure vessels and pressure relief valves could result in widespread complaints and anger.
- **Loss** – Untreated, pressure vessels and pressure relief valves could result in asset damage of between $10 million and $25 million.
- **Supply** – Untreated, pressure vessels and pressure relief valves could result in localised societal impact or short term supply interruption (hours).

1.5 Options considered

Alternatives options for inspections at compressor and meter stations for the AA6 period which have been considered are:

- **Option 1** – Maintain compliance inspection obligations of pressure vessel, relief valves and compressor rotor bundles ($7.7 million)

- **Option 2 –** Expand the inspection program to cover additional mechanical/rotational assets, structures and site contamination ($8.7 million)

An option to cease or decrease station inspections was considered but disregarded as impracticable. We have strict requirements under AS 2885 and AS 3788 to maintain transmission asset integrity and to conduct periodic inspections. The inspection frequency for pressure vessels is already conservative and applies largely non-intrusive inspection methods, so there is limited scope to decrease the inspection regime further.

The feasible options considered (1 and 2) are discussed in the following sections.

1.1.1 Option 1 – Maintain compliance inspection obligations of pressure vessel, relief valves and compressor rotor bundles

Under Option 1 we complete the high-pressure compliance related pressure relief valves and pressure vessel inspections. However, under this option we do not expand the inspections to include further assets such as structures, buildings and land, therefore missing the opportunity to manage these assets more proactively. We would also defer the contamination inspections by a minimum of five years.

1.5.1.1 Advantages and disadvantages

The advantage of Option 1 is that it does not represent a material uplift in the volume of activities. Current inspection schedules are well established and we already have the resources to conduct them. Deferring the proactive site contamination inspections means we would not have to bring in specialised resources. Option 1 is also lower cost than Option 2.

The disadvantage of Option 1 is that we would still be managing a significant portion of our meter station and compressor station assets on a reactive basis. As the assets age, this reactive approach becomes riskier and potentially more expensive as assets continue to deteriorate.

Most significantly, Option 1 fails to address the identified risk associated with contaminated sites. DBP’s compressor sites are susceptible to contamination as we operate directly with liquid hydrocarbons such as oil, and use cleaning and degreasing solvents, which over time can seep into the ground. Ad-hoc inspections conducted during the AA5 period found land contamination at two sites; Lot 51 Mason Road, Kwinana and CS8. The levels of hydrocarbon in the soil were found to be higher than those specified under AS 4482.1-20051 and should be remediated as per DWER requirements.

1.1.1.1 Achievement of objectives

Table 1.4 outlines how Option 1 will support the achievement of our vision objectives in AA6.

Table 1.4: Achieving objectives - Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y

A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

While this option partially delivers for customers and employees in terms of safety, it is not applying good asset management practices across the full suite of assets on site. Undetected corrosion or asset failure may occur, thereby resulting in expensive reactive responses that could have been avoided if structures and other mechanical/rotational assets were inspected proactively.

Option 1 would also not be environmentally and socially responsible, as we would not be proactively addressing a known contamination issue that has the potential to recur at multiple meter and compressor station sites.

1.1.1.2 Cost assessment

Under Option 1 the cost of the program would be $7.7 million, which is the cost of all the pressure compliance related expenditure for pressure relief valves and pressure vessels at compressor sites and meter station, as well as inspecting the compressor bundles stored at Jandakot.

Table 1.5: Cost assessment - Option 1, ($'000 real Dec2024)

Inspection type	2026	2027	2028	2029	2030	Total
Compressor sites						
Pressure vessels	197	197	426	153	153	**1,125**
Pressure relief valves	391	391	391	391	391	**1,955**
Compressor bundles	35	-	-	-	-	**35**
Meter stations						
Pressure vessels	628	682	725	530	628	**3,140**
Pressure relief valves	286	286	286	286	286	**1,429**
Total	**1,537**	**1,501**	**1,828**	**1,360**	**1,457**	**7,683**

1.1.1.3 Risk assessment

The following table shows the residual risk under Option 1.

Table 1.6: Risk rating impact - Option 1

Risk category	Untreated	Treated
People	High	Intermediate
Environmental	Low	Low
Supply	Intermediate	Low
DBP	High	Intermediate
Reputation	Intermediate	Negligible

Risk category	Untreated	Treated
Loss	Intermediate	Low

Undertaking only high pressure compliance inspections will reduce the overall risk to intermediate, which is ALARP. However, by not conducting soil contaminant inspections, we would not reduce the likelihood of causing an environmental risk event. This means the environmental risk would remain low, which is higher than that achieved under Option 2.

1.1.2 Option 2 – Expand the inspection program to cover additional mechanical/rotational assets, structures and site contamination

Under Option 2 we would deliver the expanded inspection program, which includes the inspections outlined in Option 1, plus additional proactive inspection of other site assets and land contamination.

1.5.1.2 Advantages and disadvantages

The major advantage of Option 2 is that it will allow us to collect better data and have a more complete understanding of the condition of our compressor and meter station assets. This will allow us to design proactive maintenance programs for site structures and other mechanical/rotational assets, and undertake proactive replacements where necessary. Option 2 will also ensure we can identify and subsequently address any land contamination issues.

The disadvantage of Option 2 is the additional cost. However, the incremental increase compared to Option 1 is only $1.0 million over the period and allows us to avoid potentially more expensive reactive repairs. We will combine inspection of pressure vessels and relief valves with other site assets where practical, optimising the inspection regime. We would, however, need to commission specialist inspectors to conduct the soil contamination testing.

1.1.2.1 Achievement of objectives

Table 1.7 outlines how Option 2 would achieve our vision objectives.

Table 1.7: Option 3 - Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	-
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

Option 2 delivers against our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient.

This option would address all the identified inspection requirements for the pressure vessels and pressure relief valves as noted in the AMP and demonstrates an inspection program that is sustainably cost efficient – adopting commercially negotiated unit rates, adjusting for lower cost, less invasive inspection methodologies where this option exists, and delivering for customers in terms of public safety and reliability by completing inspections on a cycle without impact to pipeline operations.

It also ensures health and safety of employees and contractors working across the pipeline assets by minimising risk and working within industry standards in a manner which is compliant with legislative and other regulatory requirements.

Broadening the proactive inspection regime to include structural assets, vent attenuators, exhausts, inlets and contamination ensures we are continuously improving our asset management strategies to the most proactive form of risk identification, enabling us to determine the most cost effective rehabilitation and replacement plans.

1.1.2.2 Cost assessment

The cost of this program is $8.7 million in AA6. By adopting a proactive, planned approach to inspections, we can best manage the efficient delivery of the program, minimising the need for unplanned and disruptive repair work on the network, which might otherwise result in a failure or other expensive disruption.

Table 1.8: Cost assessment - Option 2, ($'000 real 2024)

Inspection type	2026	2027	2028	2029	2030	Total
Compressor sites						
Pressure vessels	197	197	426	153	153	**1,125**
Pressure relief valves	391	391	391	391	391	**1,955**
Structural & vent attenuators	27	77	45	-	27	**175**
Exhaust/air inlet	82	82	82	82	82	**411**
Compressor bundles	35	-	-	-	-	**35**
Meter stations						
Pressure vessels	628	682	725	530	628	**3,140**
Pressure relief valves	286	286	286	286	286	**1,429**
Structural & vent attenuators	62	39	45	-	62	**207**
All sites						
Contamination	65	30	30	30	30	**185**
Total	**1,772**	**1,729**	**2,029**	**1,472**	**1,658**	**8,660**

1.1.2.3 Risk assessment

The following table shows the residual risk under Option 2.

Table 1.9: Risk rating impact - Option 2

Risk category	Untreated	Treated
People	High	Intermediate
Environmental	Low	Negligible

Risk category	Untreated	Treated
Supply	Intermediate	Low
DBP	High	Intermediate
Reputation	Intermediate	Negligible
Loss	Intermediate	Low

Delivering the expanded program will enable us to address the land contamination issue and reduce all our treated risks to intermediate or lower, reducing the environmental risk to negligible.

1.6 Summary of cost/benefit assessment

To assess the options, the costs, objectives and risk are considered for each option. A summary of the option assessment is shown in Table 1.10.

Table 1.4: Summary of cost/benefit analysis

Option	Achievement of objectives	Cost	Treated risk (integrity/reliability)
Option 1 – Maintain compliance inspection regime	This option achieves our objective of delivering for customers and being a good employer but is not sustainably cost efficient	$7.7 million	This option appropriately moderates all high/intermediate risks to ALARP, but it does not address the risk associated with soil contaminants.
Option 2 – Expanded inspection regime	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$8.7 million	This option appropriately moderates all high/intermediate risks to ALARP, including the environmental risk posed by soil contaminants.

1.7 Proposed solution

1.7.1 Why is the recommended option prudent?

Option 2 is aligned with our risk framework, asset management principles and the Safety Case, It also meets the requirement of NGR 91 that operating expenditure be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Option 1 – delivering compliance driven inspections on pressure vessels and relief valves only, would help DBP meet its regulatory obligations, however other key assets on site would remain as 'run to fail'. These other critical assets would not be managed using the same good asset management inspection strategies to remain ahead of asset failure, and inform asset management strategies that maximise asset life.

1.7.2 Estimating the efficient costs

As noted in the 'Final Plan Attachment 8.7_Cost Estimation Methodology 2026-2030', the unit rates used for all projects managed within this program include the forecast internal labour, external labour/contractors, materials, travel and other costs.

Where possible, the unit rate used to determine the cost of the program in AA5 is based on a three year average actual cost incurred in AA4.

Where this has not been possible, due to infrequent or new activities identified for AA5, these activities have been estimated based on the historical cost of the same or similar program of work. The cost of these activities would usually be determined through a competitive tender process.

Where a competitive tender has not yet occurred, the associated cost is estimated in two ways:

1. where the work is sufficiently comparable to other work – the most recent historical average unit rate or actual cost and matched to similar locations where the program is delivered externally; and
2. where the work is unique or greater than $5 million – an estimate is developed based on internal estimates from different engineering disciplines or from external engineering specialists.

1.7.3 Consistency with the National Gas Rules

National Gas Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Rule 91

The relevant opex rule is detailed below and has been extracted from the latest version of the National Gas Rules (available here: http://www.aemc.gov.au/energy-rules/national-gas-rules/current-rules):

"Division 7 Operating expenditure

91 Criteria governing operating expenditure

(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

(2) The AER's discretion under this rule is limited."

Option 1 – 'Do the volume identified in the AMP' is the recommended solution and recommends that we proceed with the inspection of pressure vessels and pressure relief valves in line with AMP.

The station inspections program is consistent with Rule 91(1), to achieve the lowest sustainable cost of providing services. Consistent with the requirements of Rule 91(1) of the National Gas Rules, DBP considers that the operating expenditure is:

- **Prudent** – The expenditure is necessary in order to meet conditions of our operating licence and provide assurance as to the integrity of pressure vessels, relief valves and other key site assets which are integral to the safe and reliable supply of gas along the DBNGP, as well as environmentally compliant sites. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- **Efficient** – The forecast expenditure is based on historical average actual costs to deliver the program of work achieved through a competitive tender process in line with our Procurement Policy and Purchasing Procedure and therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed expenditure follows good industry practice by undertaking risk-based inspections of pressure vessels and related assets in line with AS 3788. Good asset management practices involve proactive inspections to best manage the asset lifecycle, therefore the proposed expenditure is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.
- To achieve the **lowest sustainable cost of delivering pipeline services** – The sustainable delivery of services includes reducing risks to as low as reasonably practicable and reducing maintenance or replacement costs by proactively inspecting and responding to the condition of pressure vessels, relief valves and other important site assets. We have identified good asset management practices for our inspection operations that may enable us to extend the duration between inspections, and are collecting condition information from station inspections program to inform our approach moving forward. This will ensure it is carried out at the lowest sustainable cost without impacting the safe and reliable delivery of pipeline services.

NGR 74

The forecast costs in this business case are based on historical inspection costs, updated for current market conditions. Cost assessments have been conducted for each option based on the best information available at the time of developing this business case. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

1.8 Comparison to previous periods

1.8.1 AA5 comparison

In AA5, we estimate total expenditure of $5.5 million. We estimate we will exceed that forecast by around ~$600k, as we have begun undertaking the expanded inspection program outlined in this business case. Essentially we are building inspection of more assets at each meter station and compressor station site into our ongoing proactive inspection regime.

The expanded inspection regime is already yielding results in terms of identifying and addressing previously undetected risks. For example, during AA5 we detected the issue of corrosion under pipework insulation, which has subsequently driven a program of work that has allowed us to address this corrosion issue before it escalates to a point of asset failure.

1.8.1.1 AA6 forecast compared to AA5

The AA6 forecast is around $3.2 million higher than that incurred during the AA5 period. This is due to two factors:

- Increasing inspection costs: costs for this ongoing inspection regime have increased over the AA5 period in the wake of the COVID-19 pandemic. This is primarily due to higher labour and equipment costs, which are being felt across the industry. Water bath heater inspections in particular have increased due to the specialist nature of the work. There have also been changes to inspection practices over the AA5 period. For example, the inspection routine now includes high pressure clearing of heater internals during inspection, storage and disposal of waste fluids, and biocide dosing. These activities were not done during the AA4 period or at the start of AA5.
- Expansion of the inspection program to include the additional structural and mechanical/rotational assets at each meter station site discussed in this business case. The expansion program also includes land contamination inspections, which require specialist expertise.

Appendix A Comparison of risk assessments

Table A.1: Summary of risk assessment

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP13	Station inspections	Failure resulting in loss of containment, inability to protect pressure containing vessel in process upset conditions or structural failure, all of which could lead to fatal injuries, as a result of not performing mandatory fit for purpose inspections and testing.	Untreated Risk	Likelihood	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
				Consequence	Catastrophic	Minor	Severe	Major	Severe	Severe
				Risk Level	HIGH	LOW	INTERMEDIATE	HIGH	INTERMEDIATE	INTERMEDIATE
			Option 1 – Maintain compliance inspection obligations of pressure vessel, relief valves and compressor rotor bundles	Likelihood	Hypothetical	Unlikely	Remote	Remote	Remote	Remote
				Consequence	Catastrophic	Minor	Severe	Major	Minor	Severe
				Risk Level	INTERMEDIATE	LOW	LOW	INTERMEDIATE	NEGLIGIBLE	LOW
			Option 2 – Expand the inspection program to cover additional mechanical/rotational assets, structures and site contamination ($8.8 million)	Likelihood	Hypothetical	Remote	Remote	Remote	Remote	Remote
				Consequence	Catastrophic	Minor	Severe	Major	Minor	Severe
				Risk Level	INTERMEDIATE	NEGLIGIBLE	LOW	INTERMEDIATE	NEGLIGIBLE	LOW

Appendix B Overview of station inspection activities

B.1 Pressure vessel inspections

Pressure vessels on the DBNGP are typically designed to hold gas or liquid at pressures considerably higher than the ambient pressure. Australian Standard AS 1210-2010: Pressure Vessels considers a pressure vessel to be any vessel subjected to internal or external pressure. This includes all interconnecting parts and components (e.g. baffles, valves, flanges, nozzles). On the DBNGP this includes water bath heaters.

Although designed with inbuilt safety factors, pressure vessels are susceptible to a number of failure types (i.e. corrosion, mechanical damage, wear and vibration) that can result in loss of strength over time. In extreme cases, these failures can advance to a point where the strength of the vessel is insufficient for the applied stresses – causing the vessel to fail.

Figure B.1: Pressure vessel

Our pressure vessels are designed to comply with AS 1210. We are further required to comply with the inspection and testing obligations of Australian Standard AS 3788 as a condition of the pipeline licence.

There are approximately 950 pressure vessels in operation on the DBNGP, located at compressor stations, meter stations and pipelines. Over 50% of all vessels are located at compressor stations.

Common types of vessels, and their typical locations are shown in the following table.

Table B.1: Common pressure vessels by location

Type	Compressor station	Meter station
Accumulators	✓	
Launchers/receivers	✓	✓
Filters/separators/coalescers	✓	✓
Scrubbers	✓	✓
Air vessels (Receivers)	✓	
Oil coolers	✓	
Oil filters	✓	
Air dryers	✓	
Aftercoolers	✓	
Air aftercoolers	✓	
Odorant tank (stationary)		✓
Gas heater (direct electric)	✓	
Gas heater (water bath)		✓
Odorant tank (transportable)		✓
Odoriser (buried with CP tested monthly)		✓

Over 50% of all pressure vessels are located on compressor stations, with around 50 per site. More than half of the current population is over 20 years old.

AS 3788 mandates a routine inspection regime for pressure vessels. While the interval for external inspections is fixed, the standard allows for the internal inspection interval to be extended based on a proven history of integrity. The standard provides both a nominal as well as a maximum extended interval. This program includes inspection every 5 years for relief valves, 4 years for compressor stations and 8 years for meter stations.

Where previous vessel inspections indicated no corrosion or deterioration of the vessel, we can change the inspection method to non-intrusive inspection, which significantly reduces the time and costs of future inspections while remaining compliant with AS 3788.

Moving from AA4 to AA5 we identified non-intrusive inspections as appropriate for pressure vessels, and applied the lower unit rate during the period. This strategy has proved effective and we propose to continue using this more cost effective asset management strategy in AA6.

The pressure vessels to be inspected for AA6 is provided in the following table

Table B.2: Pressure vessel inspection program per category of asset over time

Pressure vessels	AA6 units						
	2026	2027	2028	2029	2030	TOTAL units	Total cost ($,000)
Compressor Station (units)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,125
Meter station (units)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3,140
Total units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**4,265**

The previous scheduled inspections for compressor station pressure vessels indicated no corrosion/deterioration. This has allowed– within the guidelines of AS 3788 - a continuation of the non-intrusive inspection method. The volume of inspection remains consistent, in line with the requirements of AS 3788.

B.2 Pressure relief valve inspections

A pressure relief valve (also referred to as pressure safety valves or PSVs) is a valve that automatically opens to discharge fluid or gas in order to relieve pressure. Pressure relief valves on DBNGP facilities form part of the pressure control and protections system, which is installed to prohibit over pressure excursions and to maintain the integrity of pressure containing systems.

Failure of a pressure relief valve during a pressure excursion could result in over pressuring of the protected equipment.

Figure B.2: Pressure relief valve

The pressure relief valves to be inspected and forecast cost for AA6 is provided in Table B.3.

Table B.3: Pressure relief valve inspection program per category of asset over time

Pressure relief valve	AA6						
	2026	2027	2028	2029	2030	Total units	Total cost ($,000)
Compressor Station (units)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,955**
Meter station (units)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,429**
Total units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**3,384**

Both the volume of inspection and unit rates for pressure relief valves remain consistent with AA5 and in line with the requirements of AS 3788.

B.3 Inspection of structures, exhausts, air inlets, vent attenuators, compressor bundles and contamination

Meter and compressor station sites host a range of structural and mechanical assets in addition to the main pressure vessels. These include site buildings, vent attenuators, exhausts, air inlets and the land itself. DBP is expanding its proactive inspection process to include these assets.

These inspections have been bundled together to achieve efficiencies of delivery, and will maximise the amount of information we can collate as the lowest cost, whilst ensuring we stay ahead of significant performance issues.

Table B.4: Site Inspection of structures, exhaust, air inlets and vent attenuators

Site inspection	AA6 (sites)					Total units	Total cost ($'000)
	2026	2027	2028	2029	2030		
Compressor Stations - Structures - Exhaust - Air inlet - Attenuators	8	9	8	5	8	38	**586**
- Compressor bundles	2	-	-	-	-	2	**35**
Meter Station - Structures	35	10	15	0	35	95	**207**
Total units	**45**	**19**	**23**	**5**	**43**	**135**	**827**

B.3.1 Site building structures

Our compressor sites and meter stations contain structures and buildings that house or protect items such as compressors, metering equipment and telecommunications equipment. The scope of structures inspection is to identify corrosion and general integrity issues, and to identify and log any changes from the last inspection so that it can be used to inform asset management decisions for replacement or refurbishment.

B.3.2 Exhausts and air inlets

The turbines operated at DBP compressor stations have air inlet manifolds as well as exhausts. The scope of the inspection is to visually inspect these assets and, in some instances, perform non-destructive testing to identify weaknesses or anomalies in the materials such that immediate remediations can be undertaken, or that they inform the asset management strategy for more prioritisation of replacement or refurbishment.

B.3.3 Vent attenuators

Vent attenuators are used to decrease the velocity of gas during depressurisation events, thereby reducing the volume (sound) of the activity to more acceptable levels. However, vent attenuators can also catch fire during use of therefore require inspections to ensure they are replaced when their integrity is compromised.

B.3.4 Compressor bundle inspections

A number of compressor station bundles are stored in long term storage in Jandakot. These bundles include high-cost compressor rotor assets and are stored in a way which is intended to ensure preservation, specifically mitigating against corrosion. These assets need to be inspected to confirm the condition of the desiccant, which is required to function as a preservative for the bundles. Where the condition of the desiccant is not adequate, it is replaced.

[redacted] are forecast for inspection and re-preservation in 2026.

B.3.5 Contamination inspections

The relevant Australian standard for assessing contaminated sites is AS 4482.1-20051, and this standard provides guidance on the investigation and sampling of sites with potentially contaminated soil, specifically focusing on non-volatile and semi-volatile compounds. It includes the formulation of data quality objectives and the design of a sampling plan to meet the objectives of the investigation.

Compressor sites are susceptible to contamination as we operate directly with hydrocarbons such as oil, but also use cleaning and degreasing solvents that, over time, seep into the ground. The allocation of budget allows for an independent expert study to be conducted in 2026 that will prioritise our sites for inspection, with a forecast rate of [redacted] per year. The first two sites have already been identified as Lot 51 Mason Rd, Kwinana and CS8, with all remaining sites to be determined on a priority basis.

1 Opex DBP14: Asset management

1.1 Project approvals

Table 1.1: DBP14 Asset management – Project approvals

Prepared by	Hugo Kuhn, Head of Engineering
Reviewed by	Jeff Kong, Head of Asset Strategy
Approved by	Tawake Rakai, GM Transmission Asset Management

1.2 Project overview

Table 1.2: DBP14 Asset management – Project overview

Description of problem /opportunity	This business case outlines DBP's approach to identifying, prioritising and responding to changing asset management requirements and functionality based on real time feedback from engineering challenges and field crews. As part of the ongoing program of asset management works we will continue to undertake the following types of asset management activities as they arise during the AA6 period: • Engineering and operational works program (subsequent costs) • Management of change projects • Asset preservation This annual ongoing program of works is consistent with the historical program. Works are prioritised through ongoing risk management and compliance to the Safety Case.
Untreated risk	As per risk matrix = Intermediate
Options considered	• **Option 1** – Allow for asset management activities at historical average levels ($5.6 million) (this is the recommended option) • **Option 2** – Do not allow provision for asset management activities (no upfront costs)
Proposed solution	Over the AA6 period, we plan to continue investing at historical levels across the range of asset management activities.
Estimated cost	The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $5.6 million.

$'000 real	2026	2027	2028	2029	2030	Total
Total	1,384	1,135	1,140	935	1,040	**5,634**

Basis of costs	All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.
Treated risk	As per risk matrix = Low
Variation from AA5	The proposed AA6 expenditure is aligned with the AA5 actuals of $5.7 million. This level of expenditure forecast for AA5 is likely to continue across future AA periods as the forecast asset management program of works tends to follow a consistent and predictable pattern of expenditure. Should significant capital or operating expenditure projects be identified that would sit outside the scope of

	this business case, individual business cases would be developed to underpin the expenditure.
Alignment to our vision	This option delivers against all of our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it provides for continuous improvement in the management of our assets.
Consistency with the National Gas Rules (NGR)	This project complies with the following National Gas Rules (NGR): **NGR 91** – Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. The proposed volume of activity is guided by our ongoing risk management process and Safety Case, and has regard to our regulatory obligations, manufacturer's recommendations, Australian and International Standards. The work will be delivered by a mix of internal and external resources. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimization with other programs of work where possible. The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with Rule 91. **NGR 74(2)** – Our forecast for the asset management program is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.
Stakeholder engagement	Our Shippers told us they highly value current levels of reliability and would be concerned if this were to change. They also expect us to maintain a strong focus on operational issues as it is important for reliability and emergency management. Our asset management program is important to ensure that only safe and operational assets are kept in service, and other assets are appropriately managed.
Other relevant documents	This business case should be read in conjunction with: • AMP TEB-001-0024-01 (General) • Risk Management Policy and Operational Risk Model (together our Risk Management Framework).

1.3 Background

The Asset Management program includes three key streams of work:

- Engineering and operational works program (subsequent costs);
- Management of change (MoC) projects; and
- Asset preservation.

1.3.1 Engineering and operational works program

The engineering and operational works program includes the costs incurred by the business following maintenance and replacement projects (i.e. subsequent costs). They fall outside the planned maintenance and replacement regimes specified in the relevant AMPs, but are required for the safe and reliable operation of the pipeline.

This program of work covers activities such as:

- inspections and overhaul of auxiliary equipment used to facilitate maintenance and inspection activities including for example crane and lifting equipment;
- GIS mapping and drawing updates to ensure asset location and as built drawings, reflect current status to facilitate optimised maintenance activities;
- revisions to control software such as [redacted] tool kit to enable safe and reliable operations;
- refinement of Maximo as an optimisation strategy in maintenance management;
- maintenance of technical documents in the document management system as required to ensure that information is accessible, accurate and reliable;
- review of critical spares, including adequacy of emergency response equipment and associated processes and plans; and
- developing a framework that outlines the technical approach to training to enable employees to be signed off and recognised as competent in critical operational and maintenance areas.

It should be highlighted that refinements and updates to software programs such as GIS and Maximo cover updates to input data and configuration rather than the software itself and are therefore distinct from upgrades of these applications which are covered in DBP 21: IT Sustaining Applications.

1.3.2 Management of change

The management of change program includes initiatives addressing defects or unsafe situations. We address an average of 150 initiatives per annum. These are typically engineering changes that are minor but can be safety or operation critical. Issues are usually identified onsite by field crews where an alternate solution to the current practice is recommended due to safety, obsolescence, operations, quality or efficiency. Issues are then assessed from an engineering perspective and proposed solutions recommended for implementation.

Examples of projects undertaken under MoC include:

- inspection and overhaul of crane lifting equipment at operational sites;
- upgrading to the latest version of gas measurement software;
- review of the Kwinana Junction UPS supply;
- odorant incineration modification;
- replacement of cathodic protection reference cells;
- adoption of new technology, equipment or spares; and
- review of process safety set points.

1.3.3 Asset preservation

Investing in the preservation of spares is crucial to ensure operational continuity. Having readily available and fit for purpose replacement linepipe, equipment and spares in storage will minimise downtime during maintenance or emergency repairs. This is particularly important for long lead items such as linepipe. Having spares on hand also supports safety, as quick replacement of faulty components reduces the risk of accidents or failures and provides a safer working environment.

Asset preservation wasn't specially identified as a line item during the AA5 submission process. However, this investment has arisen during the period as the scope of the investment was finalised in 2022, and the strategy put into practice during that year.

1.4 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, with a commitment to balance outcomes sought with delivery and cost implications considered and assessed.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Figure 1.1: Risk management principles

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible.

The risk rating assesses the consequence and likelihood of the risk. The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS 2885 and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Modify the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

Six areas are considered for each type of risk:

1. People – injuries or illness to employees and contractors or members of the public
2. Environmental impact – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Supply – disruption in the provision of services/supply, impacting customers
4. Impact on AGIG/DBP – impact on AGIG (DBP) due to restrictions and enforcement, such as regulatory enforcement or legal actions
5. Reputation – impact on stakeholders' views of AGIG (DBP), including personnel, customers, investors, security holders, regulators and the community
6. Loss – financial impact on AGIG (DBP)

The primary risk event that applies to asset management is an inability to effectively perform technical engineering functions for operational matters or inability to implement improvements and modifications, which may have significant hinderance on continued safety, environmental or operational performance.

The overall risk rating of the asset management program is presented below. Two elements of risk are rated as intermediate, three low and two negligible. This results in an intermediate risk ranking for these assets in an untreated scenario.

Figure 1.2: Untreated risk rating

	Trivial	Minor	Severe	Major	Catastrophic
Frequent		DBP			
Occasional					
Unlikely		Environmental Supply Reputation			
Remote				People	
Hypothetical	Loss				

Negligible	Low	Intermediate	High	Extreme

The drivers of the risk rating for each area are discussed below:

- **DBP –** In the event of poorly maintained records, including inaccurate or unreliable information related to our assets, DBP is unable to effectively operate and maintain its assets.
- **People –** lifting heavy equipment and operational assets in deemed high risk and is only undertaken using a permit system. Failure to undertake regular inspections and overhauls and issue the appropriate permits and training to our personnel, results in risk of serious harm to staff if equipment malfunctions or is used incorrectly.

1.5 Options considered

Two options have been considered to manage this portfolio of projects:

- Option 1 – Allow for asset management activities at historical average levels
- Option 2 – Do not allow provision for asset management activities

These options are discussed in the following sections.

1.5.1 Option 1 – Allow for asset management activities at historical average levels

This option assumes the same level of activity is required in AA6 as we undertook in AA5 and AA4. An average of $1.1 million each year is proven to enable us to adequately respond to engineering and operational issues that arise during the period to ensure the safe and reliable operations of the pipeline.

1.5.1.1 Advantages and disadvantages

The advantage of this option is that it allows us to address known risks, deficiencies and non-compliances in a timely manner. Without a provision for these activities, our people, our assets and the public may be put at unnecessary risk. Moreover, ISO 55001 requires us to embed continuous improvement in our processes. Without an adequate asset management budget, we will not meet the requirements of a well-established industry standard.

The only disadvantage of this option is that it requires expenditure and resources, albeit at historical levels.

1.5.1.2 Achievement of objectives

The following table outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.3: Achieving objectives - Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	Y
A Good Employer – Skills Development	Y
Sustainably Cost Efficient – Working within Industry Benchmarks	-
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

This option delivers against all relevant vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it allows us to address identified issues in a timely manner. Ongoing investment in asset management practices also reflects the behaviour of a socially responsible employer.

1.5.1.3 Cost assessment

This option assumes the same level of activity is required in AA6 as we undertook in AA5 and AA4. The estimated cost of this option is $5.6 million as shown in Table 1.4. The forecast is consistent with our annual average costs of the program of works undertaken in AA5 and AA4.

Table 1.4: Estimated cost of Option 1 ($'000 real Dec/2024)

Activity	2026	2027	2028	2029	2030	AA6
Engineering and operational works	549	300	305	200	305	**1,659**
Management of change	500	500	500	500	500	**2,500**
Asset preservation	335	335	335	235	235	**1,475**
Total	**1,384**	**1,135**	**1,140**	**935**	**1,040**	**5,634**

1.5.1.4 Risk assessment

The following table shows the residual risk associated with asset management if the annual average allowance is provided for works in AA6. This option moderates the threat, the frequency or the consequence to reduce the risk rank to intermediate or as low as reasonably practicable (ALARP).

Table 1.5: Risk assessment - Option 1

Risk category	Untreated	Treated
People	Intermediate	Intermediate
Environmental	Low	Low
Supply	Low	Negligible
DBP	Intermediate	Low
Reputation	Low	Negligible
Loss	Negligible	Negligible

There is an inherent risk associated with working in and around gas pipeline assets. While the asset management practices in place should reduce the likelihood of harm to our people, a rating of intermediate under our risk matrix is as low as reasonably practicable (ALARP). However, by having the appropriate asset management principles, practices and processes in place, we can reduce the likelihood of reputational and regulatory risk.

1.5.2 Option 2 – Do not allow provision for asset management activities

Under this option we would rely on the planned and scheduled maintenance and replacement programs for all assets as defined in the relevant AMPs with no explicit allowance for works to address identified major defects and subsequent works despite the risks associated with outstanding issues.

1.5.2.1 Advantages and disadvantages

There a no identifiable advantages from this approach.

The primary disadvantage of this option is that the work would still be required during AA6, but it would need to be accommodated from within the budget for other work programs. As expected, this re-prioritisation would be subject to the ongoing risk assessment process and prioritised accordingly. It would, increase the risk associated with managing the pipeline overall, as other programs are cut to accommodate ongoing asset management activities.

1.5.2.2 Achievement of objectives

Table 1.6 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.6: Alignment with objectives – Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	N
A Good Employer – Skills Development	N
Sustainably Cost Efficient – Working within Industry Benchmarks	-
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

This option does not deliver against our vision objectives of delivering for customers, being a good employer or being sustainably cost efficient.

1.5.2.3 Cost assessment

There are no upfront costs associated with this option.

1.5.2.4 Risk assessment

As shown in the table below, this option does not change the untreated risk.

Table 1.7: Risk assessment Option 2 – no provision

Risk category	Untreated	Treated
People	Intermediate	Intermediate
Environmental	Low	Low
Supply	Low	Low
DBP	Intermediate	Intermediate
Reputation	Low	Low
Loss	Negligible	Negligible

1.6 Summary of cost/benefit assessment

To assess the options, the costs, objectives and risk are considered for each option. A summary of the option assessment is shown in the following table.

Table 1.8: Summary of options assessment

Option	Achievement of objectives	Cost	Treated risk
Option 1 – Allow for asset management activities at historical average levels	This option achieves our objectives of delivering for customers, being a good employer or being sustainably cost efficient	$5.63m	This option addresses the intermediate risks and is ALARP
Option 2 – Do not allow provision for asset management activities	This option does not achieve our objectives of delivering for customers, being a good employer or being sustainably cost efficient	-	This option does not address any of the risks and is not ALARP

1.7 Proposed solution

1.7.1 Why is the recommended option prudent?

The recommended option is to continue to undertake the asset management program at a level consistent with AA4 and AA5 actual expenditure because it appropriately mitigates risk and is consistent with good industry practice. It aligns with our Risk Management Framework, asset management principles, vision objectives and regulatory requirements including the Safety Case.

It is consistent with the need to demonstrate continuous improvement when managing our assets in line with ISO 55001.

1.7.2 Estimating the efficient costs

Where applicable, forecast costs have been estimated using historical actuals, however given the specific details of the degree to which risks and non-compliance issues and their rectification projects will materialise, rolling forward historic actuals is the best measure of forecast expenditure.

1.7.3 Consistency with the National Gas Rules

Option 1 is the preferred solution and provides sufficient and timely information on the condition and performance of our assets and makes appropriate provision for prioritised rectification of issues.

NGR 91

NGR 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Specifically, the proposed asset management program is:

- **Prudent** – Undertaking asset management activities in line with histrocial average expenditure is consistent with industry standards and is critical to maintain the safety, integrity and reliable delivery of gas along the DBNGP by minimising the risk of safety related incidents affecting our staff or the public. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- **Efficient** – We consider several options to address asset management risks identified through other programs of work. This includes modifications to or new systems, processes and practices. The forecast is based on historical average annual costs from the current period. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed asset management program follows good industry practice and is consistent with our Safety Case and good industry practice. It is necessary to meet the requirements of ISO 55001.
- Required to achieve **the lowest sustainable cost of delivering pipeline services** – Ensuring known defects, issues and risks are addressed in a reasonable timeframe ensures we look after our staff, the public and our assets to the extent we can. It also reduces the total costs of providing pipeline services as it would avoid the deferral of critical works which may become reactive in nature costing more to remediate.

NGR 74

Our forecasts for the asset management program are based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

1.8 Comparison to previous periods

1.8.1 AA6 forecast compared to AA5

In AA6, operating expenditure of $5.6 million is forecast for the asset management program. Table 1.9 shows the forecast AA6 expenditure compared with actual expenditure in AA5.

Table 1.9: AA6 forecast capital expenditure, compared with AA5 actuals ($'000)

Forecast spend ($'000, Dec2024)	2026	2027	2028	2029	2030	AA6	AA5 total	Variance
Asset management	1,384	1,135	1,140	935	1,040	**5,634**	**5,693**	**-59**

1.8.2 AA5 variance

Actual expenditure during the AA5 period was $2.2 million higher than the amount determined in the AA5 Final Decision.

Table 1.10: AA5 actual expenditure compared with budget

Actual v budget ($'000, Dec2024)	2021	2022	2023	2024	2025	AA5
AA5 actual	1,204	1,516	812	1,018	1,141	**5,693**
AA5 approved	691	691	691	691	691	**3,454**
Variance	**513**	**825**	**121**	**327**	**450**	**2,239**

The higher expenditure reflected the two following unforeseen programs of work:

- a new ongoing program of work to uplift training competence worth $1.24 million; and
- an increased spend to improve our preservation of assets worth $739,000.

Neither of these two projects were specifically identified at the commencement of AA5, however the risks materialised during the period and DBP invested accordingly to ensure that risks were managed. Both these programs will continue into AA6 and are reflected in the expenditure forecast.

Appendix A Comparison of risk assessments

Table A1: Summary of risk

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP14	Asset management	Inability to effectively perform technical engineering functions for operational matters or inability to implement improvements and modifications, which may have significant hinderance on continued safety, environmental or operational performance.	Untreated Risk	Likelihood	Remote	Unlikely	Unlikely	Frequent	Unlikely	Unlikely
				Consequence	Major	Minor	Minor	Minor	Minor	Trivial
				Risk Level	INTERMEDIATE	LOW	LOW	INTERMEDIATE	LOW	NEGLIGIBLE
			Option 1 – Allow for asset management initiatives at historical average levels ($5.69 million)	Likelihood	Unlikely	Unlikely	Remote	Unlikely	Remote	Remote
				Consequence	Severe	Minor	Minor	Minor	Minor	Trivial
				Risk Level	INTERMEDIATE	LOW	NEGLIGIBLE	LOW	NEGLIGIBLE	NEGLIGIBLE
			Option 2 – Do not allow provision for asset management activities (no upfront costs)	Likelihood	Remote	Unlikely	Unlikely	Frequent	Unlikely	Unlikely
				Consequence	Major	Minor	Minor	Minor	Minor	Trivial
				Risk Level	INTERMEDIATE	LOW	LOW	INTERMEDIATE	LOW	NEGLIGIBLE

1 Opex DBP19: Pipeline and mainline valve inspections

1.1 Project approvals

Table 1.1: DBP19 Pipeline and mainline valve inspections – Project approvals

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Reviewed by	Jeff Kong, Head of Transmission Asset Strategy
Approved by	Tawake Rakai, GM Transmission Asset Management

1.2 Project overview

Table 1.2: DBP19 Pipeline and mainline valve inspections – Project overview

Description of problem /opportunity	This business case outlines the approach to inspecting the pipeline and mainline valve (MLV) assets in accordance with Australian Standard (AS) 2885 and AS 3788. There are four core inspection categories: 1. Pipeline inspections 2. Interface inspections 3. Pressure asset inspections 4. Buried flange inspections Regular inspection of the condition of these assets ensures we can intervene at the most appropriate time to take preventative action to repair any defects, such as faults in pipelines, interfaces or valves, which might otherwise cause a loss of gas, negative impact on pressure in the pipeline or even a pipeline rupture. The proposed program of work is the continuation of our ongoing inspection program, albeit at a slightly higher level to account for the 8-10 yearly in line inspections (ILI) of piggable pipeline assets due in the period.
Untreated risk	As per risk matrix = **High**
Options considered	• **Option 1** – Inspection cycle consistent with the Asset Management Plan (AMP) and Australian Standards ($17.0 million) • **Option 2** – Bring forward ILI of the section of Mainline South between Kwinana Junction and Wagerup West but otherwise implement Option 1 ($17.0 million) (this is the recommended option) • **Option 3** – Move to a replacement on failure policy (no upfront opex)
Proposed solution	The frequency of pipeline and MLV inspections is directed by the requirements of AS 2885 and AS 3788. The following inspection schedule has been reflected in the AA6 forecast. Pipeline inspections: • [redacted]-yearly ILI of the CSBP lateral in 2026 • Early ([redacted]-year) ILI of the Kwinana Junction to Wagerup West section of the mainline

	• [redacted]-yearly ILI of the Mainline and Loopline in 2028 • [redacted]-yearly ILI of Mainline South (remaining piggable section), Worsley Loop Pipeline Gas (WLPG) Loop and Southern Loop, Russel Road, Rockingham, Pinjar, Kemerton, Wellesley and Worsley laterals in 2027 • Five-yearly DCVG surveys of unpiggable pipelines not covered under the reactive dig ups resulting from previous ILI results (see DBP02: Pipeline and mainline valves) – [redacted] surveys are planned over AA6 the period • 10-yearly piping inspection under insulation and within buried pits Other inspections: • Five-yearly inspection of piping interfaces – [redacted] compressor stations, [redacted] meter stations and [redacted] MLVs per year • 12-yearly inspection of pressure vessels at MLVs – [redacted] per year • Five-yearly inspection of pressure relief valves – [redacted] per year • Five-yearly inspection of buried pits – [redacted] per year
Estimated cost	The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $17.0 million.
Basis of costs	All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.
Treated risk	As per risk matrix = Intermediate
Variation from AA5	The forecast expenditure for AA6 is $14.4 million more than the estimated expenditure in AA5 of $2.7 million. The increase in AA6 is largely the result of: • the need for ILI of several pipeline assets in line with AS 2885 and 3788 (+$12.8 million); and • an increase in the interface inspection program reflective of the increasing number of rectifications required in the AA5 period (+$0.7 million).
Alignment to our vision	Delivering the ongoing pipeline and MLV inspection program aligns with AGIG's vision in relation to: • Delivering for customers – The continued pipeline and MLV inspection program delivers for customers in terms of public safety and reliability. Maintaining and investing in our pipeline assets is critical to maintain supply our customers. By completing inspections on a cycle, we are able to prevent corrosion of the pipeline and improve our public safety and network integrity management capabilities, minimising the likelihood of uncontrolled gas escapes and extended outages. • A Good Employer – The continued pipeline and MLV inspection program ensures the health and safety of our employees and contractors working across the pipeline assets by having reliable, accurate information in relation to asset condition. • Sustainably Cost Efficient – The inspection of our pipeline and MLV assets in compliance with Australian Standards for inspections, and without impact to pipeline operations, ensures we are maintaining our assets in the most cost effective and efficient manner and working within industry benchmarks.

$'000 real Dec 2024	2026	2027	2028	2029	2030	Total
Total	1,040	6,980	7,142	979	904	**17,045**

Consistency with the National Gas Rules (NGR)	This project complies with the following National Gas Rules (NGR): **NGR 91** – Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. The proposed volume and timing of activity is guided by our asset management plans and has regard to our regulatory obligations, manufacturers' recommendations, Australian and International Standards. The work will be delivered by a mix of internal and external resources. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimisation with other programs of work where possible. The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with Rule 91. **NGR 74** - Our forecasts for pipeline and MLV inspections are based on inspection cycles set out in Australian Standards (AS 2885 and AS 3788). The forecast cost per inspection type is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.
Stakeholder engagement	Our shippers have advised us that they highly value current levels of reliability and would be concerned if this were to change. They also expect us to maintain a strong focus on operational issues as it is important for reliability and emergency management. Our pipeline and MLV inspection program comprises ongoing and periodic activities to ensure the integrity of our pipeline, laterals and loops.
Other relevant documents	This business case should be read in conjunction with: • DBP01: Compressor stations business case • DBP02: Pipeline and mainline valves business case • DBP13: Station inspections business case • Asset Management Plan General (TEB-001-0024-01) • Asset Management Plan – Corrosion Protection (TEB–001–0024-04) • Risk Management Policy and Operational Risk Model (together our Risk Management Framework)

1.3 Background

The pipeline and mainline valve (MLV) inspection program is an essential component of the asset management strategies, adopted to ensure the integrity of the pipeline is not compromised over time. Through these inspections we assess the current and forecast condition of the below ground pipework, so preventative intervention can be undertaken as needed.

There are four core categories for the Pipeline and MLV inspection program:

- Pipeline inspections:
  - In line inspections (ILI or 'pigging') of the mainline, loopline and laterals, required every ten years.

  - Direct current voltage gradient (DCVG) surveys of unpiggable pipelines, required every five years.
- Piping interface inspections, required every five years.
- Pressure asset inspections:
  - Inspection of pressure vessels at MLVs, required every 12 years.
  - Inspection of pressure relief valves, required every five years.
- Buried pit inspections, required every five years.

These inspection programs are undertaken on a periodic basis as required by the AMP and guided by industry standards and operational experience.

An overview of each category of inspections is provided in the following sections.

1.3.1 Pipeline inspections

One of the key risks associated with our transmission pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. To mitigate the risk of pipeline integrity failure, the pipelines are coated and subject to a cathodic protection (CP) system, which uses a low voltage electrical current to inhibit corrosion. The vast majority of our pipelines are also coated to inhibit corrosion.

Coatings and CP are the primary forms of preventing pipeline corrosion. It is therefore important to be able to continually measure and monitor the effectiveness of these systems and have sufficient information to be able to demonstrate the structural integrity of the pipeline.

Demonstrating structural integrity is a requirement of AS 2885.3-2012 (clause 6.5). There are two principal methods currently used by natural gas network owners/operators to monitor (and ultimately demonstrate) the structural integrity of a pipeline:

1. Measure the pipeline coating for faults with a DCVG survey and conduct direct examination (dig ups) at faults to inspect for coating and pipeline deterioration.
2. Measure the thickness and condition of the pipeline steel by in line inspection and verify the results by direct examination.

Both these methods are accepted as an efficient and effective way of maintaining pipeline integrity. However, it has become good industry practice and standard pipeline integrity management to use ILI when this tool is able to be operated with DCVG surveys and CP protection levels where ILI can not be operated.

Section 6.6.1 of AS 2885.3-2012 states:

> *The Licensee shall consider the use of an inline inspection tool capable of detecting the flaws that may exist in a pipeline.*

Of the 3,098 km of pipeline (including loopline and laterals), more than 90% is piggable. Approximately 245 km of pipe is unpiggable. This means we have a mix of both ILI and DCVG activities in our program of works.

Where we install new pipelines, we seek to make them piggable to the extent practicable. Historically we have also sought to augment pipelines and sections of pipeline to make them piggable where it is economic to do so. We have included forecast capex in AA6 to conduct studies to determine the feasibility and cost of the augmentation/reconfiguration of the unpiggable section of the Mainline South and make it piggable (see business case DBP02: Pipeline and mainline valves).

Figure 1.1: Example of unpiggable pipe

1.3.1.1 Inline inspections (ILI)

The integrity of a gas pipeline body and its welding system can be monitored using ILI tools, also known as intelligent pigs. These devices are driven by gas pressure and travel along inside a pipeline to ascertain pipeline integrity and condition. Internal inspection utilising an ILI tool provides a thorough analysis of pipeline defects and locations, and identifies features such as:

- general corrosion;
- pitting corrosion;
- circumferential gouging;
- axial gouging;
- mill defects;
- proximity of ferrous metal; and
- dents.

Data gathered by intelligent pigging is analysed using run comparison software ([redacted][1]) to forecast rates of corrosion. The [redacted] analysis allows us to identify areas for excavation and inspection, known as dig ups. These dig ups are included as capex (see DBP02: Pipeline and MLV).

[1] The ILI relies upon a software called [redacted] to enable direct signal-to-signal comparison between two inspections. It is used to determine the changes in defect sizes between two inspections and calculates the growth or change over time. It can also detect and report on any new anomalies that have developed since the previous inspection.

Comparison of ILI results over time allows actively growing anomalies to be distinguished from passive or pre-existing pipe wall features. The information gathered from the inspections is used to guide investment decisions on repairs, maintenance and replacement. It supports the development of an annual list of prioritised assets for further inspection and/or rectification which is ultimately incorporated into our annual work program.

The frequency of intelligent pigging depends on the age of the pipe and regulatory requirements. The DBNGP mainline and looplines are scheduled to be inspected in this way every eight to ten years. The frequency may be extended depending on the results of the next ILI run. Laterals are usually inspected after the mainline and/or loops as this optimises delivery and the utilisation of inhouse resources.

Based on an 8-10 year cycle, the following pipelines are due for pigging in the AA6 period:

- 2026: CSBP Lateral
- 2028:
  - Mainline
  - Loopline
- 2029:
  - Mainline South
  - Pinjar, Russel Road, WLPG Loop, Rockingham, Kemerton and Wellesley laterals
  - Southern Loop and Worsley Lateral

It should be highlighted that costs vary for each physical pigging project due to the various types of tools used, the specification of the pipeline, number of pigs runs required, pipeline pig trap locations (urban/rural) and government approvals.

Figure 1.2: DCVG and example of corrosion

1.3.1.2 Direct current voltage gradient (DCVG) surveys

Where pigging is not possible, AS 2885 requires the integrity of pipeline protective coatings to be assessed using a DCVG survey.

A DCVG survey involves taking surface measurements of the amount of electrical current that is escaping through coating faults into the surrounding soil. The coating fault 'indications' are indicated by a voltage drop and denoted as an %IR value[2].

Depending on the size of the IR value, the location of the pipeline, CP performance and previous dig up history, the section of pipeline where coating indications have been identified will be excavated and directly examined. The dig ups are part of the capital works program (see DBP02: Pipeline and mainline valves).

DCVG and dig ups only provide an indication of the pipeline coating condition at a sample of locations where the pipeline steel condition has been assessed. Results must be extrapolated for the remaining sections of the pipeline.

1.3.2 Inspection of piping interfaces

The interface of pipe between below ground and above ground is the area where corrosion is most commonly found. This is because the protective coating fails due to extended ultraviolet (UV) exposure, with the delaminated coating creating a crevice where moisture is captured and causes corrosion. This is where CP is ineffective as the delaminating coating separates the CP from the crevice. Corrosion then occurs undetected. This was the main cause of the Varanus Island incident. We have identified several instances on the DBNGP where corrosion has occurred with only a few millimetres of wall thickness remaining, such as Thomas Road Meter Station.

The risk further increases as assets age. The photos below show examples of corrosion underneath interface pipework arising due to the failure of interface coating, ultimately causing crevice corrosion.

[2] Voltage drop (or %IR) is a relative value of the current waste through the coating defect and takes values from 0% to 100%.

Figure 1.3: Photos of interface corrosion detected at facilities – features hidden behind the tape wraps

Our pipeline and MLV inspection program has been developed using more than 40 years of operational experience on the DBNGP. Systematic inspection of all interfaces ensures all areas of corrosion are identified in a timely manner and the most appropriate intervention is undertaken. The remediation of defects is undertaken as capex and is included in DBP02: Pipeline and MLV.

There are approximately 150 sites in total that need interface inspections. The program of inspections is presented in the following table.

Table 1.3: 15-year view of above and below ground inspections

Facility type	Actual / estimated AA5 p.a.	Forecast AA6 p.a.
Compressor stations	[redacted]	[redacted]
Meter stations	[redacted]	[redacted]
MLVs	[redacted]	[redacted]
Total inspections	[redacted]	[redacted]

1.3.3 Pressure asset inspections

Both visual internal and external inspections of pressure assets are required under AS 3788: Pressure Equipment, In-Service Inspection. Our inspection regime includes ultrasonic thickness testing, as the risks associated with malfunction can become a serious safety hazard. Should a pressure asset fail there are risks such as projectiles, explosions and even high-pressure injection injuries should people (customers or our staff) be present.

We inspect all pressure vessels and pressure relief valves on the DBNGP periodically, consistent with AS 3788 and our AMP.

1.3.3.1 Pressure vessel inspection

There are approximately 950 pressure vessels in operation on the pipeline. Around 15% of these are on pipeline and MLV assets including:

1. Accumulators
2. Launchers/receivers
3. Aftercoolers
4. Gas heaters (direct electric)

More than half of the current population is over 20 years old.

As pressure vessel inspections are crucial for ensuring the safety and reliability of operating pressure containment equipment, we inspect and proactively maintain them. Pressure vessel integrity issues can occur due to improper installation, faulty or incorrect pressure relief parts, unmanaged corrosion, rectification works disregarding specifications or poor quality maintenance.

The inspection of these four types of pressure vessels on the pipeline occurs every 12 years. Six pressure vessels will be inspected each year throughout AA6 consistent with the AMP.

1.3.3.2 Pressure relief valve inspection

A pressure relief valve is a valve that automatically opens to discharge fluid in order to relieve pressure. Pressure safety valves (PSVs) are a type of pressure relief device. Pressure relief valves on DBNGP facilities form part of the pressure control and protections system, which is installed to limit over pressure excursions and maintain the integrity of pressure containing systems.

Pressure relief valves are critical. They are used to relieve the pressure in the pipeline as soon as it reaches a pre-set level based on the maximum allowable operating pressure (MAOP) of the pipeline. The pressure is relieved to a safe area via vent pipes before the system fails catastrophically.

There are approximately 1500 pressure relief valves in operation on the pipeline. Around 25% of these are on pipeline and MLV assets. PSVs are inspected every five years. As per our ongoing PSV inspection program, we will inspect pressure relief valve assets at 19 of the 157 MLV sites.

1.3.4 Buried flange inspections

During pipeline infrastructure construction it is not possible to weld all joints, and therefore flanges are utilised to make pipeline and infrastructure connections in a safe and efficient manner.

Flanges are not always above ground. Below ground flanges are typically wrapped in a protective shroud and/or coating. We have found several significant cases of corrosion these wrapped and buried flanges. We have therefore commenced a program of works to dig up, unwrap and inspect these connections every five years to ensure they are in good working order.

This program is commensurate with other programs where flanges are inspected as part of capital works programs for compressor stations and meter stations. However, this program is opex as there would be no opportunity for rectification as part of the inspection.

1.3.5 Buried pit inspections

There are around 50 pits along the DBNGP, these excavated areas are used for different purposes including:

- Maintenance and Inspection: These pits allow access to the pipeline for routine inspections, repairs, and maintenance activities.
- Valve and Equipment Installation: They provide space for installing and accessing valves, meters, and other essential equipment.
- Environmental and Safety Measures: Buried pits can also be used to manage environmental impacts and ensure safety during pipeline operations.

Buried pit inspections involve examining the excavated areas along the pipeline to ensure their integrity and safety. We look for corrosion, assess the structural integrity of the pit, and environmental compliance and check for leaks.

In the AA6 period we will prioritise inspection of all 50 of our buried pits. We will deliver the program based on geography from south to north at around 10 per year.

1.4 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, with a commitment to balance outcomes sought with delivery and cost implications considered and assessed.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Figure 1.4: Risk management principles

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible.

The risk rating assesses the consequence and likelihood of the risk. The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS ISO 31000 Risk Management – Principles and Guidelines, and AS/NZS 2885 Pipelines-Gas and Liquid Petroleum, and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Modify the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Six areas are considered for each type of risk:

1. People – injuries or illness to employees and contractors or members of the public
2. Environmental impact – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Supply – disruption in the provision of services/supply, impacting customers
4. Impact on AGIG/DBP – impact on AGIG (DBP) due to restrictions and enforcement, such as regulatory enforcement or legal actions
5. Reputation – impact on stakeholders' views of AGIG (DBP), including personnel, customers, investors, security holders, regulators and the community
6. Loss – financial impact on AGIG (DBP)

Note that risk is not the sole determinant of what investment is required. Many other factors such as growth, cost, efficiency, sustainability and the future of the network are also considered when we develop engineering solutions. The risk management framework provides a valuable tool to manage our assets, and prioritise our works program, however it is not designed to provide a binary (yes/no) trigger for investment. As prudent asset managers, we apply our experience and discretion to manage and invest in our distribution networks in the best interests of existing and potential customers.

The primary risk event associated with not doing pipeline and MLV inspection is that pipeline or piping defects (e.g. corrosion) go undetected and hence not rectified, leading to breach of asset integrity and capability to maintain fit or purpose pressure containment, resulting in uncontrol release of natural gas.

The overall risk rating of pipeline and MLV inspections is outlined below. This results in an overall high-risk rating for these assets in an untreated scenario.

Figure 1.5: Untreated risk rating – Pipeline and mainline valve inspections

	Trivial	**Minor**	**Severe**	**Major**	**Catastrophic**
Frequent					
Occasional					
Unlikely			Reputation Supply	Environment DBP Loss	
Remote					People
Hypothetical					

Negligible	**Low**	**Intermediate**	**High**	**Extreme**

Pipeline and MLV inspections are aimed at mitigating the risk of defects, such as faults in pipelines, interfaces or valves, which might otherwise cause a loss of gas, negative impact on pressure in the pipeline or even a pipeline rupture. Specifically:

- **DBP –** Gas release, rupture or explosion as a result of corrosion at interfaces, failure of pressure relief valves or failure of pressure vessels presents a major risk to the effective operation of the DBNGP. Failure to undertake inspections in line with Australian Standards is likely to jeopardise our operating licence. It is also likely to cause unacceptable cost consequences for us.

- **People –** Gas release, rupture or explosion as a result of corrosion at interfaces, failure of pressure relief valves or failure of pressure vessels presents a major risk to public safety and the health and safety of employees and could result in multiple fatalities in extreme circumstances.
- **Reputation –** Failure to undertake inspections in line with Australian Standards is likely to cause widespread complaints, anger and concern, particularly from our safety regulator, DEMIRS, and other pipeline operators.
- **Loss –** Gas release, rupture or explosion as a result of corrosion at interfaces, failure of pressure relief valves or failure of pressure vessels presents a severe risk of asset damage, including to surrounding assets[3].
- **Supply –** Gas release, rupture or explosion as a result of corrosion at interfaces, failure of pressure relief valves or failure of pressure vessels presents a severe risk to supply continuity, where damaged assets are inoperable for extended periods of time, thereby impeding our ability to achieve its Shipper commitments.

1.5 Options considered

Different options have been considered to ensure our pipeline and MLV assets continue to function safely, reliably and accurately. The options are:

- Option 1 – Inspection cycle consistent with the AMP and Australian Standards
- Option 2 – Bring forward ILI of the section of Mainline South between Kwinana Junction and Wagerup West but otherwise implement Option 1
- Option 3 – Move to a replacement on failure policy

The options are discussed in the following sections.

1.5.1 Option 1 – Inspection cycle consistent with the AMP and Australian Standards

Under this option the volume of inspections undertaken in AA6 will reflect the requirements identified in the AMP, aligned to standard industry practice, comply with the requirements of AS 2885 and AS 34788 and be conducted in line with the DBNGP Safety Case.

Through our works planning and scheduling processes, we have sought to optimise the schedule of works required to undertake the ILI for the mainline, laterals and loops, with the laterals scheduled to be inspected after the mainline and/or loops. This ensures the most efficient delivery and maximises the utilisation of inhouse resources, thereby keeping inspection costs as low as practicable.

The works program is as follows:

[3] Similar incidents have occurred in Boston in 2018 where a gas explosion caused structural damage to a nearby property and resulted in a fatality.

Pipeline inspections:

- [redacted]-yearly ILI of the CSBP lateral in 2026
- [redacted]-yearly ILI of Mainline South (part), WLPG Loop and Southern Loop, Russel Road, Rockingham, Pinjar, Kemerton, Wellesley and Worsley laterals in 2029
- [redacted]-yearly ILI of the Mainline and Loopline in 2028
- Five-yearly DCVG surveys of unpiggable pipelines – [redacted] per year in addition to dig up and rectification works (see DBP02: Pipeline and mainline valves)

Other inspections:

- Five-yearly inspection of piping interfaces – [redacted] compressor stations, [redacted] meter stations and [redacted] MLVs per year
- 12-yearly inspection of pressure vessels at MLVs – [redacted] per year
- Five-yearly inspection of pressure relief valves – [redacted] per year
- Five-yearly inspection of buried flanges – [redacted] survey
- Five-yearly inspection of buried pits – [redacted] per year

1.5.1.1 Advantages and disadvantages

The advantage of Option 1 is that it ensures we are keeping up to date with our inspection program and meeting our regulatory requirements and so will be able to identify asset defects in a timely manner.

The disadvantage of Option 1 is that by not bringing forward ILI of the 289km section of Mainline South, we are foregoing the opportunity to potentially defer or eliminate a large number of dig ups from our pipeline and MLV capex program (this is discussed in Option 2).

There is no difference in inspection costs between Option 1 and Option 2, only a slight shift in timing.

1.5.1.2 Achievement of objectives

Table 1.4 outlines how pipeline and MLV inspections will support the achievement of our vision objectives in AA6.

Table 1.4: Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y

Vision objective	Alignment
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

This option delivers for customers in terms of public safety and working within industry benchmarks by complying with Australian Standards for inspections, and reliability and customer service by completing inspections on a cycle without impact to pipeline operations. It also ensures health and safety of employees and contractors working across the pipeline assets by having reliable, accurate information in relation to pipeline and MLV asset conditions.

This is the most cost effective option as it reflects an optimised delivery schedule, keeping the costs associated with inspecting our piggable pipelines as low as practicable.

1.5.1.3 Cost assessment

The cost of this option is $17.0 million over AA6. The proposed work, including volume and value, under this option is provided in Table 1.5 below.

Table 1.5: Cost assessment – Option 1

($'000)	Measure	2026	2027	2028	2029	2030	Total
ILI	Kms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DCVG	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Above/below ground	Units						
	Unit cost						
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pressure vessel	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pressure relief valve	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buried flanges	Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buried pits	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total		**1,040**	**675**	**7,142**	**7,284**	**904**	**17,045**

By adopting a proactive, planned approach to inspections, we can best manage the efficient delivery of the program, which also minimises the need for unplanned and disruptive repair work on the network that is typical in reactive approaches to asset management.

1.5.1.4 Risk assessment

Conducting the volume of pipeline and MLV inspections as required in the AMP in AA6 does 'moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

Table 1.6: Risk assessment Option 1

Risk category	Untreated	Treated
People	High	Intermediate
Environmental	High	Intermediate
Supply	Intermediate	Low
DBP	High	Intermediate
Reputation	Intermediate	Low
Loss	High	Low

This option is considered ALARP as it inspects all mainlines, looplines and laterals to detect defects early so that they can be effectively controlled to deliver gas safely and reliably to meet the needs of our customers and gas producers.

1.5.2 Option 2 – Bring forward ILI of the section of Mainline South between Kwinana Junction and Wagerup West

This option is consistent with Option 1, but under this option we would bring forward the ILI of the 289 km section of Mainline South between Kwinana Junction and Wagerup West to help provide comparative information on the significant number of defects found during the last pig run to confirm defects that are stagnant - manufacturing based and those that correlate to coating defects and exposed to corrosion.

The last ILI run on the Mainline South – Kwinana Junction – Wagerup West pipeline was conducted in 2021. The next run is due in 2029. We have recently re-evaluated the [redacted] data from the 2021 and 2013 ILIs and have completed sample excavations to assess these defects and this indicates that the defects are manufacturing-related (during coating). The defects are deemed safe.

The confidence factors used in the original [redacted] analysis to identify defects were too conservative. The analysis used apparent growth of >18% to flag that a defect was growing and needed further investigation. Upon reviewing our asset management practices, we consider an 18% threshold represents too great a growth factor. We have therefore reassessed the [redacted] results using a 10% growth threshold.

If we apply the 10% threshold, the ILI results show that 129 locations along the Mainline South have experienced defect growth of >10%. (Ref [redacted] report KMS-PI-REP-004-01.) Of the 129 dig ups, we know [redacted] are required, as these locations were flagged in the original [redacted] analysis and are already known to have ERF>1. However, this still leaves [redacted] further potential dig ups along the Mainline South.

Given the high volume (and high cost) of potential dig ups, under Option 2 we propose to bring forward the scheduled ILI of Mainline South by two years, to 2027. This would help us better understand the significance and growth of these defects and assess whether the [redacted] additional dig ups are required. We can then use the data from the 2027 ILI run to prioritise and potentially eliminate a significant proportion of dig ups.

As discussed in DBP02: Pipeline and MLV, by bringing forward the ILI, as well as bringing forward [redacted] of the [redacted] ERF>1 dig ups to 2025, we should be able to reduce the dig up capex program. Depending on the 2027 ILI results, we may be able to constrain the AA6 dig up program on this section of pipeline to the [redacted] outstanding ERF>1 digs only. This would reduce the overall dig up program from [redacted] (across all pipelines) to [redacted].

1.5.2.1 Advantages and disadvantages

The advantage of Option 2 is that it ensures we are keeping up to date with our inspection program and meeting our regulatory requirements, and so will be able to identify asset defects in a timely manner. A further advantage of Option 2 is that it may allow us to defer up to 99 dig ups that have been identified on a section of Mainline South.

There is no difference in inspection costs between Option 1 and Option 2, only a slight shift in timing.

1.5.2.2 Achievement of objectives

The following table outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.7: Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	Y
Delivering for Customers – Customer Service	Y
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

This option delivers for customers in terms of public safety and working within industry benchmarks by complying with Australian Standards for inspections, and reliability and customer service by completing inspections on a cycle without impact to pipeline operations. It also ensures health and safety of employees and contractors working across the pipeline assets by having the most up-to-date, reliable and accurate information in relation to pipeline and MLV asset conditions.

This option is sustainably cost efficient as it does not increase the cost of the ILI program, but will reduce the risk to ALARP by helping us prioritise our dig up program to address the highest risks first, or remove a significant portion of dig ups from the program altogether.

1.5.2.3 Cost assessment

The cost of bringing forward the ILI of part of Mainline South is consistent with Option 1, but the spend is incurred in 2027 instead of 2029.

Table 1.8: Cost assessment – Option 2 (Mainline South ILI brought forward to 2027)

($'000)	Measure	2026	2027	2028	2029	2030	Total
ILI	Kms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DCVG	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Above/below ground	Units						
	Unit cost						
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pressure vessel	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pressure relief valve	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buried flanges	Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buried pits	Units	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unit cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total		**1,040**	**6,980**	**7,142**	**979**	**904**	**17,045**

1.5.2.4 Risk assessment

Table 1.9 shows that option 2 does 'moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

Table 1.9: Risk assessment Option 2

Risk category	Untreated	Treated
People	High	Intermediate
Environmental	High	Intermediate
Supply	Intermediate	Low
DBP	High	Intermediate
Reputation	Intermediate	Low
Loss	High	Low

1.5.3 Option 3 – Reactive action only

With this option, inspections would not be undertaken, and corrective action would instead occur when an issue arises. Any preventive action would rely on the availability of asset performance data being readily available to alert us to potential or actual failure, and our resultant ability to mobilise teams to undertake necessary reactive and/or emergency works.

1.5.3.1 Advantages and disadvantages

The advantage of Option 3 is that it results in no upfront opex. However, the disadvantages of a reactive action only approach are significant.

The DBNGP is a critical asset in Western Australia's energy sector and economy as a whole. The consequences of allowing the pipeline to fail or even to deteriorate to a level where failure is likely are extremely severe. If inspections are stopped or even pared back, then the risk of asset failure increases significantly, giving rise to safety concerns, disruption of supply and financial penalties. The 2008 Varanus Island incident highlighted the importance of domestic gas supply and the consequences if corrosion goes unchecked.

Moving to a reactive only inspection regime is therefore not a prudent option.

1.5.3.2 Achievement of objectives

The following table outlines how Option 3 to replace only on failure will support the achievement of our vision objectives in AA6.

Table 1.10: Achieving objectives

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	N
Delivering for Customers – Customer Service	N
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N

Vision objective	Alignment
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	-

This option does not deliver against any of our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as reactive correction significantly increases the risk of defects, such as faults in pipelines, interfaces or valves, which might otherwise cause a loss of gas, negative impact on pressure in the pipeline or even a pipeline rupture.

1.5.3.3 Cost assessment

With this option, no cost would be incurred for inspections, as the business would move to a reactive (corrective) approach to asset management. However, the costs are likely to be higher than preventative maintenance due to the need to mobilise crews reactively, which can include penalty rates, as well as the high likelihood of incurring additional expenditure on repair works where leaks and/or explosions damage adjacent assets.

Supply interruptions to customers would be severe (and potentially unacceptable) and we may incur some costs if there are contractual commitments made which would prompt the need for penalty or other termination payments to be made.

1.5.3.4 Risk assessment

A reactive only approach to asset management in AA5 does not 'moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

Table 1.11: Risk assessment Option 3

Risk category	Untreated	Treated
People	High	High
Environmental	High	High
Supply	Intermediate	Intermediate
DBP	High	High
Reputation	Intermediate	Intermediate
Loss	High	High

By not undertaking the inspections program, the risk rating would be unchanged from the untreated risk assessed and would not comply with our operational risk management framework which requires us to treat high risks to 'Moderate the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.

1.6 Summary of cost/benefit assessment

To assess the options, the costs, objectives and risk are considered for each option. A summary of the option assessment is shown below.

Table 1.12: Summary of cost/benefit analysis

Option	Achievement of objectives	Cost	Treated risk (integrity/reliability)
Option 1 – Inspections consistent with the volume required in the AMP	This option achieves our objectives of delivering for customers, being a good employer or being sustainably cost efficient	$17.0 million	This option addresses the high/intermediate risks to DBP/People/ Environment/ Reputation/Loss/Supply
Option 2 – Bring forward ILI of the section of Mainline South between Kwinana Junction and Wagerup West	This option achieves our objectives of delivering for customers, being a good employer or being sustainably cost efficient	$17.0 million	This option addresses the high/intermediate risks to DBP/People/ Environment/ Reputation/Loss/Supply
Option 3 – Reactive action only	This option does not achieve our objectives of delivering for customers, being a good employer and being sustainably cost efficient	No upfront opex required	This option does not change any inherent risks

1.7 Proposed solution

1.7.1 Why is the recommended option prudent?

Option 2 is the preferred solution as it provides the most up-to-date, accurate and reliable information on the integrity of our pipeline assets. Over and above option 1 it will help us prioritise our dig up program (see DBP02: Pipeline and mainline valves) to achieve the greatest risk reduction as early as possible.

Option 1 is consistent with our AMP and Australian Standards, and is consistent with good industry practice. It aligns with our Risk Management Framework, asset management principles, vision objectives and regulatory requirements including the DBNGP Safety Case. However, given option 2 is no more expensive, and results in a greater risk reduction, option 1 is not the preferred option.

Option 3 is a reactive approach which significantly increases our risks in relation to safety and does not meet Australian Standards. Further, option 3 is not appropriate as any deliberate increase or reduction in inspection activity for these assets would be based on an arbitrary assessment driven not by appropriate, industry standard asset management disciplines, but by the adoption of an artificial regulatory framework driven cap on expenditure and therefore the inspection cycle of some of our most critical assets.

1.7.2 Estimating the efficient costs

As noted in the 'Final Plan Attachment 8.7_Cost Estimation Methodology 2026-2030', the unit rates used for all projects managed within this program include the forecast internal labour, external labour/contractors, materials, travel and other costs.

The unit rates used to determine the cost of the program in AA6 are based on historical costs of the same or similar programs in AA5.

1.7.2.1 Estimating efficient costs

The costs are estimated by identifying the activities to be undertaken given the inspection cycle outlined in the AMP and then multiplying by the appropriate unit rate for materials and labour. As noted in the 'Final Plan Attachment 8.7_Cost Estimation Methodology 2026-2030', the forecast unit rates for all projects/initiatives managed within this program are inclusive of internal labour, external labour/contractors, materials, travel and other costs. Specialist engineering disciplines, procurement and construction management activities will be provided by internal resources. The delivery of the work and supply of required materials will be undertaken by external resources.

1.7.3 Consistency with the National Gas Rules

Option 1 is the preferred solution and provides us with sufficient and timely information on the condition and performance of our mainline, loop line and laterals. This information is then used upon to make assessments which ultimately prioritise repairs or replacement activities on pipeline and MLV assets.

NGR 91

The relevant opex rule is detailed below and has been extracted from the latest version of the National Gas Rules (available here: http://www.aemc.gov.au/energy-rules/national-gas-rules/current-rules):

"Division 7 Operating expenditure

91 Criteria governing operating expenditure

(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

(2) The AER's discretion under this rule is limited."

Option 1 – 'Inspection cycle consistent with the Asset Management Plan and Australian Standards' is the recommended solution and recommends that we proceed with the pipeline and MLV inspections in line with AMP, Australian Standards and the Safety Case.

The proposed inspection program is consistent with the requirements of NGR 91(1), specifically the proposed expenditure is:

- **Prudent** – Inspection of our pipeline and MLV assets in line with the industry standard timeframes maintains the safety, integrity and reliable delivery of gas along the DBNGP by minimising the risk of an undetected pipeline integrity issue resulting in a loss of containment incident. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.
- **Efficient** – Our forecasts for when inspections will fall due is based on the latest condition information gathered from prior inspections, Australian Standards and our Safety Case. The forecast cost for each activity type is based on a three-year average historical costs or recent similar project costs as applicable. An optimised inspection program represents a more cost-effective solution over the life of the asset than a more piecemeal approach of prioritising assets with supply redundancy. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed inspection program follows good industry practice of aligning inspections with commitments embedded within the AMP, Australian Standards and the Safety Case.
- Required to achieve **the lowest sustainable cost of delivering pipeline services** – Undertaking the inspection program in a proactive, planned and optimised schedule reduces total costs over the life of these assets, where unplanned failure could lead to a loss of containment incident resulting in public and staff safety issues and asset damage. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimisation with other programs of work where possible.

NGR 74

Our forecasts for pipeline and MLV inspections are based on inspection cycles set out in Australian Standards (AS 2885 and AS 3788). The forecast cost per inspection type is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

The proposed volume and timing of activity is guided by our asset management plans and has regard to our regulatory obligations, manufacturer's recommendations, Australian and International Standards. The work will be delivered by a mix of internal and external resources. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimisation with other programs of work where possible. The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with Rule 91.

1.7.4 Justification of non-base year cost

The preventative inspection program for pipeline and MLV assets is influenced not by financial or regulatory periods, but by the frequency of inspection noted within the relevant AMP which is based on pipeline license requirements, vessel standards and pressure safety valve standards.

The use of a base year would not take into consideration the core purpose of this activity, which is the cyclical assessment of the health of the asset based on all current knowns and would artificially inflate the cost of the inspection program.

1.8 Comparison to previous periods

1.8.1 AA6 forecast compared to AA5

In AA6, operating expenditure of $17.0 million is forecast for the pipeline and MLV inspections program. Table 1.13 shows the forecast AA6 expenditure compared with actual expenditure in AA5.

Table 1.13: AA5 forecast operating expenditure, compared with AA5 actual ($'000 real 2024)

Forecast spend ($'000, Dec2024)	2026	2027	2028	2029	2030	AA6 total	AA5 total	Variance
Operating expenditure	**1,040**	**675**	**7,142**	**7,284**	**904**	**17,045**	**2,839**	**14,206**

The forecast expenditure for AA6 is $14.2 million more than the estimated expenditure in AA5 of $2.8 million.

The increase in AA6 is largely the result of:

- the need for ILI of several critical pipeline assets in 2028 and 2029 in line with AS 2885 and 3788 (+$12.8 million); and
- an increase in the interface inspection program reflective of the increasing number of rectifications required in the AA5 period (+$0.7 million).

Table 1.14 provides the forecast pipeline and MLV program.

Table 1.14: AA6 forecast works program ($'000 real 2024)

Activity	2026	2027	2028	2029	2030	Total
ILI	170	6,305	6,305	-	-	**12,780**
Inspection of interface assets	279	211	373	515	440	**1,818**
Inspection of pressure assets	265	265	265	265	265	**1,325**
Leakage and DCVG surveys	203	76	76	76	76	**980**
Buried pit inspections	123	123	123	123	123	**615**
Total	**1,040**	**6,980**	**7,142**	**979**	**904**	**17,045**

1.8.2 AA5 variance

Actual expenditure during the AA5 period was relatively consistent with the amount determined in the AA5 Final Decision (see Table 1.15). However, we reprioritised certain activities to account for unexpected inspections and maintenance activity.

Table 1.15: AA5 actual expenditure compared with budget

Actual v budget ($'000, Dec2024)	2021	2022	2023	2024	2025	AA5
AA5 actual	830	523	250	810	426	**2,839**
AA5 approved	941	435	435	435	435	**2,681**
Variance	**-116**	**85**	**-187**	**458**	**61**	**301**

Appendix A Comparison of risk assessments

Table A1: Summary of risk assessment

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP19	Pipeline and main line valve inspections	Pipeline or piping defects (e.g. corrosion) go undetected and hence not rectified, leading to breach of asset integrity and capability to maintain fit or purpose pressure containment, resulting in uncontrol release of natural gas.	Untreated Risk	Likelihood	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
				Consequence	Catastrophic	Major	Severe	Major	Severe	Major
				Risk Level	HIGH	HIGH	INTERMEDIATE	HIGH	INTERMEDIATE	HIGH
			Option 1 – Inspection cycle consistent with the Asset Management Plan (AMP) and Australian Standards	Likelihood	Hypothetical	Remote	Remote	Remote	Remote	Remote
				Consequence	Catastrophic	Major	Severe	Major	Severe	Severe
				Risk Level	INTERMEDIATE	INTERMEDIATE	LOW	INTERMEDIATE	LOW	LOW
			Option 2 – Bring forward ILI of the section of Mainline South between Kwinana Junction and Wagerup West but otherwise implement option 1	Likelihood	Hypothetical	Remote	Remote	Remote	Remote	Remote
				Consequence	Catastrophic	Major	Severe	Major	Severe	Severe
				Risk Level	INTERMEDIATE	INTERMEDIATE	LOW	INTERMEDIATE	LOW	LOW
			Option 3 – Move to a replacement on failure policy	Likelihood	Remote	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
				Consequence	Catastrophic	Major	Severe	Major	Severe	Major
				Risk Level	HIGH	HIGH	INTERMEDIATE	HIGH	INTERMEDIATE	HIGH

1 Opex DBP25: Decommissioning

1.1 Project approvals

Table 1.1: DBP25 Decommissioning – Project approvals

Prepared by	Jeff Kong, Head of Asset Strategy Andrew Stanwix, Principal Engineer Mechanical C&P RE
Reviewed by	Jeff Kong, Head of Asset Strategy
Approved by	Tawake Rakai, GM Transmission Asset Management

1.2 Project overview

Table 1.2: DBP25 Decommissioning – Project overview

Description of problem /opportunity	Non-operational assets and facilities degrade over time, posing a risk to the environment, public and employee safety and future operations (where the asset may again be required in the provision of services). Decommissioning or mothballing of non-operational assets and facilities reduces risk to the environment and public and employee safety. Decommissioning renders the asset permanently unusable while mothballing ensures there can be a smooth transition into reoperation where the asset is required to deliver services in future. There are eight sites identified for full decommissioning during AA6 including: • CS10 [redacted] units 1 and 2 • Redundant equipment at the Wagerup facilities • Westlime meter station • Oakley Road meter station • Mondarra Meter Station (interconnects with the Parmelia Pipeline) • Temporary diesel engine alternators • Run 6 and 8 shutdown valves at Pinjar Power Station • Buried sump tank in the Dampier Facilities compound
Untreated risk	As per risk matrix = Intermediate
Options considered	• **Option 1** – Decommission identified assets ($649,000) (this is the recommended option) • **Option 2** – Do not proactively decommission assets ($1.5 million, plus ongoing costs)
Proposed solution	Over the AA6 period, we will decommission eight sites. In 2026, the [redacted] units at CS10 will be removed and equipment salvaged. The units were made redundant with the expansion of Stage 4, 5A and 5B with larger [redacted] units installed. There are a number of smaller decommissioning projects scheduled for 2027 with two smaller sites and five medium sites that require rectification works to make them safe.

Estimated cost

The forecast direct cost (excluding overheads) during the next five-year period (AA6) is $648,800 (Dec2024).

Total	350	299	-	-	-	**649**

Basis of costs

All costs in this business case are expressed in real unescalated dollars December 2024 unless otherwise stated.

Treated risk

As per risk matrix = **Low**

Variation from AA4

The forecast expenditure for AA6 is $172,000 more than the forecast expenditure in AA5 of $477,000.

Decommissioning is not comparable between years or AA periods due to the inherent lumpy nature and difference in scope of the projects in the program. However, the incremental increase in AA6 wholly relates to the decommissioning of the assets at CS10.

Alignment to our vision

This option delivers against all of our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it executes decommissioning consistent with AMP and manufacturer/OEM recommendations for useful life.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 91 – Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

The proposed volume and timing of activity is guided by our asset management plans and has regard to our regulatory obligations, manufacturer's recommendations, Australian and International Standards. The work will be delivered by a mix of internal and external resources. External resources and materials are procured competitively in line with our procurement policy and purchasing procedure to ensure efficient costs. The method and timing of delivery also considers bundling and optimisation with other programs of work where possible.

The opex is therefore of a nature that would be incurred by a prudent service provider, acting efficiently, in line with good industry practice and to achieve the lowest sustainable cost of delivering pipeline services and is consistent with Rule 91.

NGR 74(2) – Our forecasts for decommissioning are based on the risks our identified assets pose should they be left in the field. The forecast cost per project is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

Stakeholder engagement

Our shippers told us they highly value current levels of reliability and would be concerned if this were to change. They also expect us to maintain a strong focus on operational issues as it is important for reliability and emergency management. Our decommissioning program is important to ensure that only operational assets are kept in service, and other assets are appropriately and safely decommissioned.

Other relevant documents	This Business Case should be read in conjunction with: • Asset Management Plan (TEB-001-0024-07) • Asset Decommissioning Procedure (TEB-003-0077-01) • Risk Management Policy and Operational Risk Model (together our Risk Management Framework)

1.3 Background

All physical DBNGP assets are managed in accordance with the policies and principles set out in our asset management system framework. A key principle of the framework is effective management of asset risks which includes identification of risks and evaluation of the adequacy of controls in terms of physical safeguards and asset maintenance requirements.

Our asset management system framework spans five phases:

1. Asset development or enhancement
2. Operation
3. Maintenance, including routine and emergency
4. Review and improvement
5. Asset replacement and decommissioning

Redundant assets are decommissioned when there is no longer a need for its function/service and retention of the asset presents risks in terms of safety, environment, financial, impact on DBP and/or operation. Decommissioning is executed in accordance with Asset Decommissioning Procedure (TEB-003-0077-01), which is normally initiated through the Management of Change (MoC) process.

All "live" assets present some inherent risk, whether it is from pressurised hydrocarbons, stored fuel/oil, electrical energy, or any other form of hazard. Assets that have reached the end of their operational life are decommissioned or placed in a mothballed state as a strategy to eliminate or mitigate risk. This approach also applies to assets that have been suspended in operation for an extended period .

Live assets require maintenance to ensure their integrity. The decommissioning or mothballing of assets that are no longer required for operational purposes reduces the overall burden on maintenance resources and reflects a prudent and efficient operating philosophy.

Once decommissioned, consideration is given to the appropriate disposal of the asset where there is no economic benefit in retaining it. The plan for decommissioning and/or disposal of a redundant asset will be formulated meeting the requirements of AS 2885.3 and assessed as part of the MoC process.

During the AA6 period we have eight sites that are scheduled for decommissioning as follows:

1.3.1 CS10 units 1 and 2 which are currently mothballed, and the hot bleed system

This project involves the full physical disconnection and removal of two cent aur gas turbine driven compressor packages, and associated piping and pressure vessels for the hot bleed system. It also involves the removal of structural platforms, air inlets, exhausts and associated peripheries such as cabling.

These are redundant assets following the expansion and installation of [redacted] units driven by growth during Stage 4, 5A and 5B expansions and that have not been used since. They have not been maintained, and consequently their condition is deteriorating and becoming unsafe, with risks of large falling objects such as structural platforms, exhaust stacks and air inlet components.

It would cost around $200,000 to return the CS10 units to a safe condition, and around $10,000 per year to maintain. We would also need to paint the hot bleed system which would be required in the AA6 period, and every 10 years at a cost of around $100,000.

1.3.2 Wagerup facilities

This project involves the physical removal of all above and below ground redundant piping and associated equipment from site.

This piping has not been in use for several years and serves no purpose. The site now contains a mix of live and disused piping. Retaining the redundant piping is a source of confusion, which may lead to the wrong pipe being isolation or a live pipe being neglected. Decommissioning these assets removes a safety risk to our operational staff.

1.3.3 Westlime meter station

This project involves the physical disconnection of small bore pipework, valves and instrumentation at the meter station and the permanent removal of meter skid and all associated equipment.

This meter station has not been in operation for many years and the outlet is disconnected. The asset therefore no longer serves a purpose. The pipework and associated equipment remain connected and pressurised, which is an unnecessary risk of leakage and/or loss of containment. The maintenance of these assets in a safe condition costs around $40,000 per annum.

1.3.4 Oakley Road meter station

This project involves the physical disconnection of pipework at the below ground valve and the permanent removal of meter skid and all associated equipment.

These assets are not operational and the condition is deteriorating presenting unnecessary risk of a loss of containment event. The maintenance of these assets (in a safe condition) costs around $40,000 per annum.

1.3.5 Mondarra meter station

This project involves the physical disconnection and removal of two DN150 gas measurement runs connecting the DBNGP to the Parmelia Pipeline. Each run consists of piping, a filter vessel, valves, and associated equipment such as instrumentation, pipe supports and civil foundations. Blind flanges will be installed to cap the pipeline.

These assets are no longer in use following decision by APA to decommission the interconnection. The maintenance of these redundant assets costs around $40,000 per annum.

1.3.6 Temporary diesel engine alternator - CS9

This project involves the removal of the temporary 850 kW DEA package including the disconnection of skid and associated services, cranage and transport from site and disposal of the assets. There are also updates to control systems required.

The temporary DEA is no longer in use and costs around $20,000 per annum to maintain in a safe condition.

1.3.7 Run 6 and 8 shutdown valves at the Pinjar Power Station

This project involves the removal of shut down valves and associated controls on each of the two runs, blinding of the flange at the pressure reduction and metering run outlet, blinding of the flange at the start of the skid outlet, and preservation of the outlet line with a nitrogen blanket. The outlets from these runs include soil to air interfaces and buried piping.

These units are not in use and cost around $40,000 per annum to maintain.

1.3.8 Buried sump tank in the Dampier Facilities compound

This project involves the isolation dig up and removal of the sump tank, as well as the disposal of any contaminated soil and backfill of the site.

The sump tank was used for draining of liquids from the station scrubber. However, this scrubber has been removed and relocated to Kwinana Junction. The sump tank, which is showing signs of significant deterioration, no longer serves a purpose but presents a risk of collapse and inundation. This is a significant safety risk.

1.3.9 Common works

Drawings, databases and documents will be updated accordingly for each decommissioning project.

1.4 Risk assessment

Risk management is a constant cycle of analysis, treatment, monitoring, reporting and then identifying once again, as shown below in Figure 1.1 with a commitment to balance outcomes sought with delivery and cost implications considered and assessed.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur.

Figure 1.1: Risk management principles

Based on these two key inputs, the risk assessment and derived risk rating then guides the actions and activities required to ensure safety and compliance are not compromised, while delivery of this outcome is done as efficiently and effectively as possible.

The risk rating assesses the consequence and likelihood of the risk. The risk of an event associated with failure of an asset is rated based on the combined effect of the consequence and likelihood rating to provide an overall risk rating. This risk rating guides the risk management and mitigation activities and facilitates prioritisation.

Our Operational Risk Framework is based on AS/NZS 2885 and requires all identified risks ranked as intermediate or above to be addressed. For risks ranked as high we must *'Modify the threat, the frequency or the consequence to reduce the risk rank to intermediate or lower'.*

Six areas are considered for each type of risk:

1. People – injuries or illness to employees and contractors or members of the public
2. Environmental impact – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. Supply – disruption in the provision of services/supply, impacting customers
4. Impact on AGIG/DBP – ability of AGIG (DBP) to operate the asset(s) without restrictions due to regulatory enforcement or legal actions
5. Reputation – impact on stakeholders' views of AGIG (DBP), including personnel, customers, investors, security holders, regulators and the community
6. Loss – financial impact on AGIG (DBP)

The primary risk event is the inadequate decommissioning of non-operational assets, which will degrade over time, compromising safety of people and a risk to the environment.

The overall risk rating of decommissioning is presented in Figure 1.2. Three elements of risk are rated as intermediate, two low and one negligible. This results in an intermediate risk ranking for these assets in an untreated scenario.

Figure 1.2: Untreated risk rating

	Trivial	Minor	Severe	Major	Catastrophic
Frequent					
Occasional		DBP	People Environmental Loss		
Unlikely		Reputation			
Remote					
Hypothetical	Supply				

Negligible	**Low**	**Intermediate**	**High**	**Extreme**

The decommissioning program is required as per the Safety Case, particularly where decommissioning presents a significant opportunity to eliminate or mitigate risks of leaving the assets live. The overall risk rating of not undertaking decommissioning works is identified as intermediate.

The specific risk categories are:

- **People** – Untreated, there are safety risks related to leaving assets in a live condition despite them not being required for service, especially where staff are required to work in or around assets that have not been appropriately decommissioned or mothballed.
- **Environmental** – Untreated, pressurised hydrocarbons, stored fuel/oil, electrical energy, or any other form of hazard pose risks to the environment.
- **Loss** – Untreated, there is the potential for assets to be damaged, including those kept "live" where they are no longer required for service.

1.5 Options considered

Two options have been considered to manage these obsolete / redundant assets:

- Option 1 – Decommission identified assets
- Option 2 – Do not proactively decommission assets

These options are discussed in the following sections.

1.5.1 Option 1 – Decommission identified assets

Under Option 1 we will decommission the eight identified facilities during the AA6 period:

- CS10 units 1 and 2 and the hot bleed system
- Wagerup facilities
- Westlime meter station
- Oakley Road meter station
- Mondarra meter station interconnect with Parmelia
- The temporary diesel engine alternator at CS9
- Run 6 and 8 shutdown valves at Pinjar Power Station
- Buried sump tank in the Dampier Facilities compound

1.5.1.1 Advantages and disadvantages

The primary advantage of this option is that it removes all risk associated with these redundant assets. It also allows us to eliminate recurrent maintenance costs associated with these assets.

There are limited disadvantages to this option, beyond it requiring resources to conduct the work. However, the overall cost of this option is expected to be marginally lower than if the assets remained in situ.

1.5.1.2 Achievement of objectives

Table 1.3 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.3: Alignment with objectives – Option 1

Vision objective	Alignment
Delivering for Customers – Public Safety	Y
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	Y
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	Y
Sustainably Cost Efficient – Delivering Profitable Growth	-
Sustainably Cost Efficient – Environmentally and Socially Responsible	Y

This option delivers against our vision objectives of delivering for customers, being a good employer and being sustainably cost efficient and executes decommissioning consistent with AMP requirements and manufacturer/OEM recommendations for useful life.

1.5.1.3 Cost assessment

The forecast opex under this option is $648,800 for the AA6 period and includes the decommissioning of assets at eight sites. More information of the each of the projects and the cost estimate is provided in Appendix A.

Table 1.4: Summary of costs - Option 1

($'000)	2026	2027	2028	2029	2030	Total
CS10	350	-	-	-	-	**350**
MLV	-	15	-	-	-	**15**
Small sites	-	29	-	-	-	**29**
Medium sites	-	255	-	-	-	**255**
Total	**350**	**299**	**-**	**-**	**-**	**649**

Internal resource requirements and external costs are calculated primarily on engineering, planning and site work requirements using previous construction work as a basis. However, an accurate cost for the work will not be known until approvals are received and the detailed decommissioning/mothballing plan has been created for each asset/facility.

1.5.1.4 Risk assessment

This option reduces the risk associated with these assets to ALARP as they are fully decommissioned. The treated risk is shown in Table 1.5.

Table 1.5: Treated risk – Option 1

Risk category	Untreated	Treated
People	Intermediate	Low
Environmental	Intermediate	Negligible
Supply	Negligible	Negligible
DBP	Intermediate	Low
Reputation	Low	Negligible
Loss	Intermediate	Negligible

1.5.2 Option 2 – Do not proactively decommission assets

This approach assumes that no assets or facilities are decommissioned or mothballed during AA6. We will need to maintain these assets to extend their lives where possible.

1.5.2.1 Advantages and disadvantages

The advantage of this option is that it requires no allocation of resources to conduct the decommissioning work. However, this is considerably outweighed by the disadvantages of leaving these assets in situ. As a prudent operator we have a responsibility to remove known hazards where practicable to do so. These assets serve no longer serve any purpose, therefore there is no benefit to keeping them in the system.

1.5.2.2 Achievement of objectives

Table 1.6 outlines how this option will support the achievement of our vision objectives in AA6.

Table 1.6: Achieving objectives - Option 2

Vision objective	Alignment
Delivering for Customers – Public Safety	N
Delivering for Customers – Reliability	-
Delivering for Customers – Customer Service	-
A Good Employer – Health and Safety	N
A Good Employer – Employee Engagement	-
A Good Employer – Skills Development	-
Sustainably Cost Efficient – Working within Industry Benchmarks	N
Sustainably Cost Efficient – Delivering Profitable Growth	Y
Sustainably Cost Efficient – Environmentally and Socially Responsible	N

This option does not deliver against any relevant vision objectives of delivering for customers, being a good employer and being sustainably cost efficient as it exposes significant risks to safety, environment, operations and financial performance by leaving assets in service beyond their useful life and requiring ongoing maintenance activities to be undertaken which is inconsistent with prudent and efficient practice.

1.5.2.3 Cost assessment

The estimated costs associated with this option are indirect as a result of increasing and ongoing maintenance costs. No direct decommissioning expenditure will be incurred in AA6.

Based on our current expenditure on operations and maintenance of the assets and facilities currently proposed for decommissioning, it is expected that we would need to spend $530,000 upfront to make the assets safe, and then $190,000 of capex will continue to be incurred each year to ensure that the assets are in maintained in a safe state.

Table 1.7: Cost to maintain redundant assets

Assets	Upfront	Ongoing capex (per annum)
CS10 units and hot bleed system	$500,000	$20,000
Wagerup facilities	-	-
Westlime meter station	-	$40,000
Oakley Road meter station	$30,000	$30,000
Run 1 and 2 of the Parmelia Export Pipeline Loop	-	$40,000
Temporary DEA	-	$20,000
Run 6 and 8 shutdown valves at Pinjar Power Station	-	$40,000
Buried sump tank at Dampier Facilities	-	-
Total	**$530,000**	**$190,000**

1.5.2.4 Risk assessment

This option does not change the risk rating from the untreated scenario. However, it should be highlighted that the likelihood of an event (primarily safety related) will continue to increase as the assets age should they not be maintained. This means the cost associated with keeping them in the field would also increase.

1.6 Summary of cost/benefit assessment

The costs, objectives and risk are considered for each option. A summary of the option assessment is shown in Table 1.8.

Table 1.8: Summary of options assessment

Option	Achievement of objectives	Cost	Treated risk (integrity/reliability)
Option 1: Decommission identified assets	This option achieves our objectives of delivering for customers, being a good employer and being sustainably cost efficient	$648,800	Addresses the intermediate risks to People/ Environment/ Loss
Option 2: Do not proactively decommission assets	This option does not achieve our objectives of delivering for customers, being a good employer or being sustainably cost efficient	$1.5 million in AA6 and $190,000 per annum thereafter	Does not address the intermediate risks to People/ Environment/ Loss

1.7 Proposed solution

1.7.1 Why is the recommended option prudent?

The recommended option is to continue to undertake decommissioning work at the nominated eight sites in order to sufficiently mitigate or eliminate risks associated with those assets no longer required for service and consistent with good industry practice. It provides rigour in the evaluation and assessment of assets most requiring decommissioning or mothballing and prioritises them accordingly. It aligns with our risk management framework, asset management principles, vision objectives and regulatory requirements including the Safety Case.

Option 2 provides no improvement in risk rating and would pose unacceptable risks in relation to pressurised hydrocarbons, stored fuel/oil, electrical energy, or any other form of hazard where assets are kept live beyond their useful life. Option 2 would also incur expenditure that is neither prudent nor efficient by requiring ongoing maintenance expenditure on non-operational assets.

1.7.2 Estimating the efficient costs

The costs are estimated by identifying the activities to be undertaken given the historical actual volumes and then multiplying by the appropriate unit rate for materials and labour.

As noted in the 'Final Plan Attachment 8.7 Cost Estimation Methodology 2021-2025', the forecast unit rates for all projects/initiatives managed within this program are inclusive of internal labour, external labour/contractors, materials, travel and other costs.

Internal resource requirements as well as external costs are dictated primarily by the engineering and planning as well as the site work required, and forecasts have been based on previous construction work. However, an accurate cost for the work will not be known until approvals are received and the detailed decommissioning/mothballing plan has been created for each asset/facility.

1.7.3 Consistency with the National Gas Rules

Option 1 is the preferred solution and ensures our non-operational assets are maintained or decommissioned in a safe and cost-effective manner. It is consistent with our AMP, Australian Standards, the Safety Case and our Asset Decommissioning Procedure.

NGR 91

Rule 91 requires that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Specifically, the proposed decommissioning expenditure is:

- **Prudent** – Decommissioning of non-operational assets in line with the industry standard timeframes maintains the safety, integrity and reliable delivery of gas along the DBNGP by minimising the risk of assets causing public or employee safety events. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.

- **Efficient** – We consider several options to treat the risks associated with non-operational assets. This includes keeping them in the field and maintaining them as we would do for operational assets, mothballing them, decommissioning onsite them and decommissioning and disposing of them. The program is developed using risk assessments of these assets and optimised for delivery. The forecast is based on a bottom-up build of historical costs of similar projects. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – The proposed decommissioning program follows good industry practice of assessing the risk of leaving non-operational assets live and is consistent with the AMP, Australian Standards, the Safety Case and the Asset Decommissioning Procedure.

- **Required to achieve the lowest sustainable cost of delivering pipeline services** – Decommissioning assets when they are non-operational and not likely to be required again reduces the total costs over the remaining life of these assets. If we were to leave the assets live, we would bear the operational risk associated with the physical assets and well as the costs associated with the necessary maintenance.

NGR 74(2)

Our forecasts for decommissioning are based on the risks our identified assets pose should they be left in the field. The forecast cost per project is based on historical costs. Therefore, the forecast is arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances.

1.8 Comparison to previous periods

1.8.1 AA6 forecast compared to AA5

In AA6, operating expenditure of $648,800 is forecast for the decommissioning program. Table 1.9 shows the forecast AA6 expenditure compared with actual expenditure in AA5.

Table 1.9: AA5 forecast capital expenditure, compared with AA5 actual ($'000, Dec24)

Forecast spend ($'000, Dec2024)	2026	2027	2028	2029	2030	AA6	AA5 total	Variance
Decommissioning	350	299	-	-	-	**649**	**477**	**172**

Decommissioning is not comparable between years or AA periods due to the inherent lumpy nature and difference in scope of the projects in the program. However, the incremental increase in AA6 wholly related to the decommissioning of the assets at CS10. Table 1.10 provides an overview of the forecast decommissioning program.

Table 1.10: AA6 forecast decommissioning program ($'000, Dec24)

Activity	2026	2027	2028	2029	2030	AA6
CS10 units	281	-	-	-	-	**281**
CS10 hot bleed system	69	-	-	-	-	**69**
Wagerup facilities	-	51	-	-	-	**51**
Westlime meter station	-	51	-	-	-	**51**
Oakley Road meter station	-	51	-	-	-	**51**
Run 1 and 2 of the Parmelia Export Pipeline Loop	-	51	-	-	-	**51**
Temporary DEA	-	51	-	-	-	**51**
Run 6 and 8 shutdown valves at Pinjar Power Station	-	29	-	-	-	**29**
Buried sump tank at Dampier Facilities	-	15	-	-	-	**15**
Total	**350**	**299**	**-**	**-**	**-**	**649**

1.8.2 AA5 variance

Actual expenditure during the AA5 period was $136,000 lower than the amount determined in the AA5 Final Decision.

Table 1.11: AA5 actual expenditure compared with budget ($'000, Dec24)

Actual v budget ($'000, Dec2024)	2021	2022	2023	2024	2025	AA5
AA5 actual	-	308	-105*	273	-	477
AA5 approved	-	-	306	306	-	613
Variance		**308**	**-412**	**-33**		**-136**

* Note: An accounting accrual was corrected in 2023

Although no expenditure was forecast until 2023, a project was required to address safety issues and reduce future potential electrical risk associated with the redundant equipment. Redundant electrical equipment that has been decommissioned still has potential to be re-energised if it is accidentally de-isolated and therefore, we spent $203,000 to eliminate this risk.

Over the period we have completed or will have completed decommissioning four of the proposed projects:

- HiSmelt Meter Station & Offtake
- Carnarvon Power Station Lateral
- Mondarra Meter Station
- 5 LM500 water bath heaters

We also decommissioned the Red Gully inlet which was not included in the forecast.

The decommissioning of the Eneabba meter station was not completed due to a change in the customer's plans for the site. The decommissioning of the Westlime meter station was deferred until AA6 to allow the removal of the redundant electrical equipment within the period which was prioritised due to the safety risk.

Appendix A Comparison of risk assessments

Table A1: Summary of risk assessment

Project Ref No	Description	Primary Risk Event	Proposed Action		People	Environmental	Supply	DBP	Reputation	Loss
DBP025	Decommissioning	Inadequate decommissioning of non-operational assets, which will degrade over time, potentially compromising safety of people and a risk to the environment.	Untreated Risk	Likelihood	Unlikely	Unlikely	Hypothetical	Unlikely	Unlikely	Unlikely
				Consequence	Severe	Severe	Trivial	Severe	Minor	Severe
				Risk Level	INTERMEDIATE	INTERMEDIATE	NEGLIGIBLE	INTERMEDIATE	LOW	INTERMEDIATE
			Option 1 – Decommission identified assets ($649,000)	Likelihood	Unlikely	Unlikely	Hypothetical	Unlikely	Unlikely	Unlikely
				Consequence	Minor	Minor	Trivial	Minor	Trivial	Trivial
				Risk Level	LOW	LOW	NEGLIGIBLE	LOW	NEGLIGIBLE	NEGLIGIBLE
			Option 2 – Do not proactively decommission assets ($1.5 million, plus ongoing costs)	Likelihood	Unlikely	Unlikely	Hypothetical	Unlikely	Unlikely	Unlikely
				Consequence	Severe	Severe	Trivial	Severe	Minor	Severe
				Risk Level	INTERMEDIATE	INTERMEDIATE	NEGLIGIBLE	INTERMEDIATE	LOW	INTERMEDIATE